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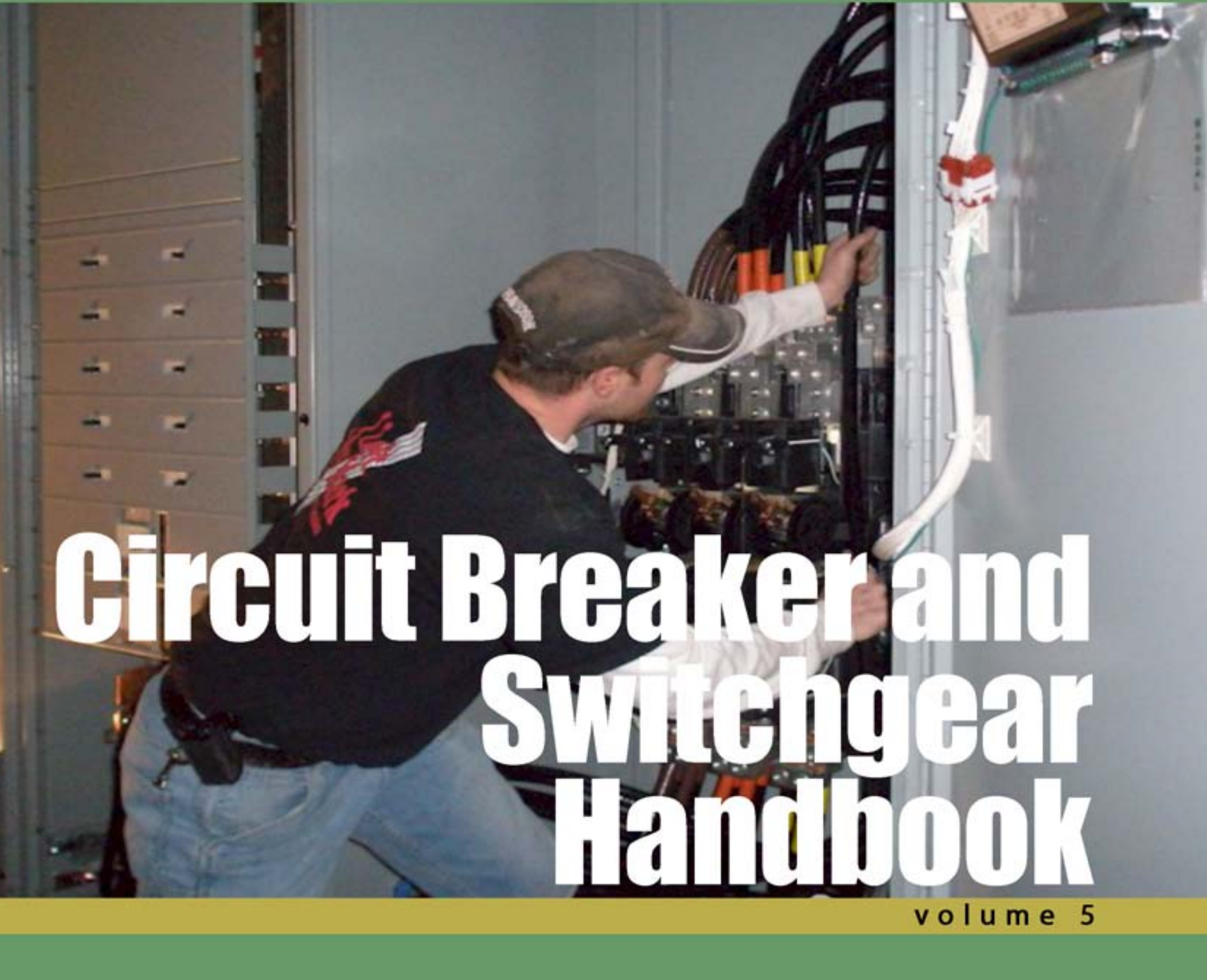

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volume 5

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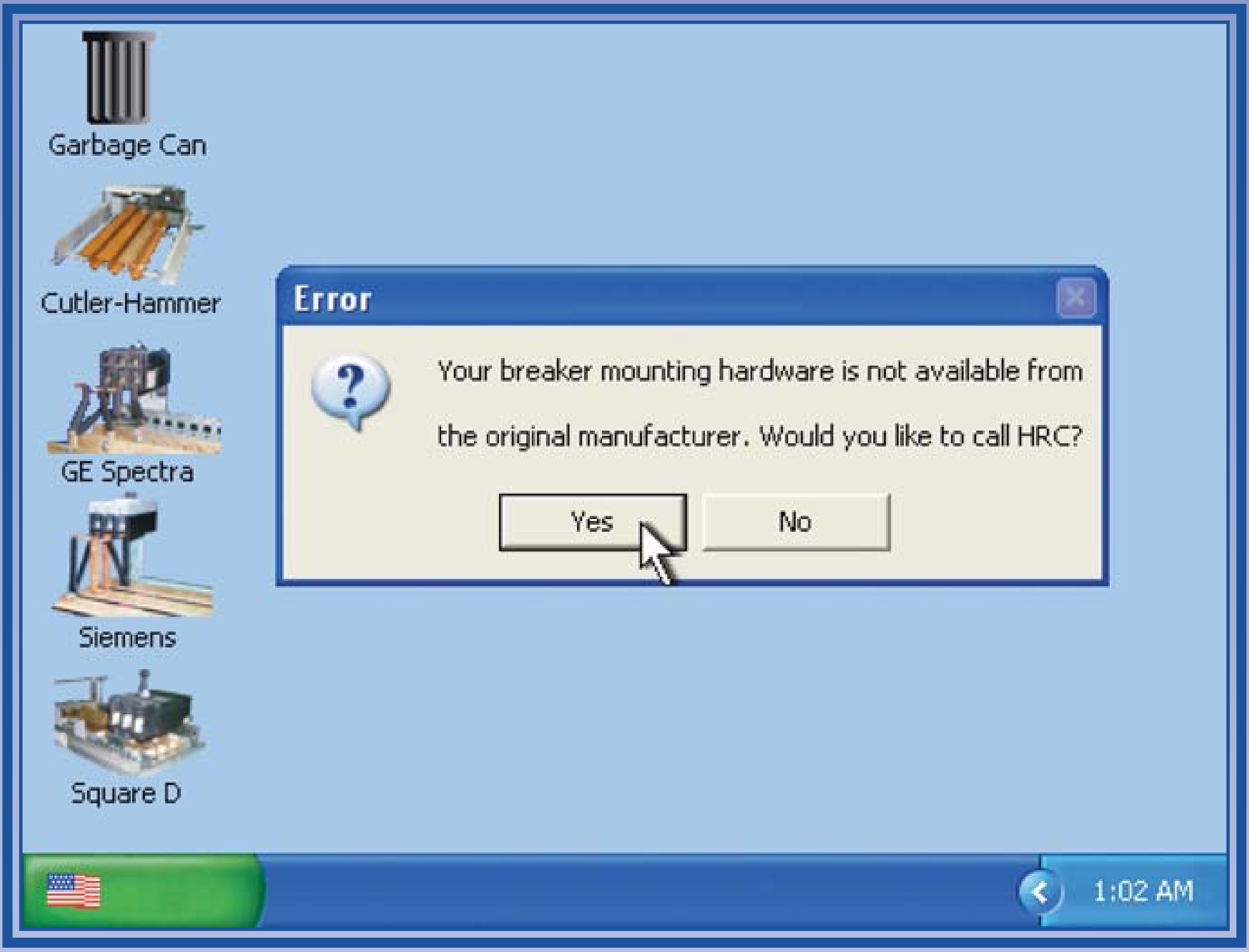

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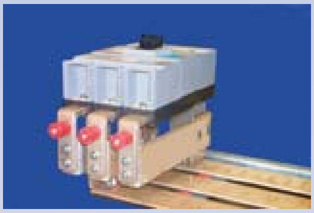

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SOME LESSONS LEARNED FROM COMMISSIONING SUBSTATION AND MEDIUM VOLTAGE SWITCHGEAR EQIPMENT

Andrew R. Leoni and John P. Nelson, NEI Electric Power Engineering Inc.

I. INTRODUCTION

Over the course of an average day, somewhere in the world a major electrical failure occurs at a petrochemical plant. For many outages due to corrosion, heat build-up, insulation failures (some accelerated by contamination or humidity), animals, improperly prepared terminations, or misoperation, the cause is quickly identified and corrected, and the equipment is placed back in service. With properly designed, installed, and maintained protection systems, damage is usually limited in scope. However, in cases with extensive and possibly collateral damage, the cause may not be found until a thorough analysis and investigation is complete. Unfortunately, the conclusion is never appealing. Often, the equipment or system:

- was designed incorrectly,
- was installed incorrectly, or
- did not perform as designed.

Furthermore, the cause of many failures is either inconclusive or misdiagnosed. For those instances when the system did not perform as designed, there are two common causes:

- Lack of maintenance
- Improper commissioning

Commissioning a substation or medium-voltage switchgear line-up both safely and on schedule requires significant planning, documentation, and effort, as discussed by Bowen in [1]. Most new switchgear is assembled and tested in the factory.

However, some equipment suppliers may claim to test the switchgear but in fact may not truly perform comprehensive testing. The switchgear is disassembled for shipment, and then reassembled at the job site. The result may be the creation of many mechanical and electrical problems. Start-up lists and test procedures, including IEEE standards [2] [3] [5] [6], testing organization procedures, electric utility procedures, and equipment manufacturer guidelines exist to help discover these problems. However, many times the electric system was designed correctly, constructed with the best intentions, but not thoroughly inspected and tested by qualified personnel before being placed in service.

This article is not a complete treatise on the subject of testing and inspection required prior to or after energizing medium voltage switchgear and substation equipment. It does, however, discuss many important aspects of ensuring the protection systems for substation or medium-voltage switchgear are, from an electrical standpoint, ready to be placed in service. The following sections discuss:

- Important items to be considered in the commissioning planning stage
- Practical methods for checking protective device circuits
- Common commissioning oversights and avoiding them

II. COMMISSIONING AND START-UP

Commissioning planning begins in the design stage. It should form a part of the specifications for the equipment purchased and installed, and must address the electrical and mechanical aspects of the installation. During procurement, careful review of submitted drawings and bills of material will help avoid conflicts in the field. The start-up process provides one of the final opportunities to review compliance with specifications and drawings. The test results form a baseline on the initial condition of the equipment. The process should ensure the equipment:

- is assembled and connected correctly,
- has the proper ratings,
- has devices which are calibrated, and
- the overall system will perform as designed.

Due to the complexity of modern protective relay systems, as discussed in [4], and the number of parties involved, the potential for errors and omissions must be accounted for in the planning stage.

For any given job, the equipment supplier, a separate testing group, the receiving organization, the design engineer, and/or end customer may provide start-up services. In all cases, a competent authority should review the test results, conduct a final inspection, and perform system tests. This review ensures that the individual systems, proven by others to be correctly installed, will in fact work together as intended. Some of these tests and inspections occur before energization and others after load has been placed on the new equipment. Improper testing and start-up may jeopardize the reliability of the equipment, the process, and the safety of personnel. The following section discusses tests that should be completed for protective device circuits.

III. PROTECTIVE DEVICE CIRCUIT TESTS

A. DC CONTROL CIRCUITS

DC control circuits are tested to verify that switching devices, such as circuit breakers, respond correctly to all control signals, and indicating devices, such as panel-mounted lights or remote control room monitor graphics, operate correctly within the designed logic. Control devices and operations to be verified with functional testing include:

- Control switch trip and close functions and associated indicating lights

- Protective relay tripping
- Automatic transfer schemes
- Lock-out relays and electrical interlocks
- Local, remote, and supervisory (SCADA) control and indication

Functional tests insure errors within DC control circuits are detected. These functional tests begin with checking wiring accuracy and end when the last string of logic, or more appropriately, the last contact in the last control device, is proven functional. When faced with a complicated DC schematic for a circuit breaker, this may appear to be an intimidating and time-consuming task. However, the inspection and testing must be thorough, safe and performed without damaging any equipment.

In order to accomplish this, the following items should be considered:

- the source of the equipment
- the possibility of damaging relays
- undesirable circuit breaker operation

If equipment is new and thoroughly factory tested, less attention may be needed on the internal wiring. Not all suppliers have adequate quality controls in place to warrant the assumption that the equipment, if properly assembled in the field, is ready for service. If factory tests were witnessed or the equipment is from a "trusted" source, focus can be placed on confirming connections made during the field installation. If equipment was existing and significantly modified, or used equipment was purchased without being tested, extra care must be exercised and all internal connections should be reviewed before applying control power.

In order to avoid protective relay damage or accidental breaker operation, remove and/or open all test paddles and plugs, test switches, fuses, and DC power supply connections to the relays before applying power. Removing power supply connections, whether they are made directly to the relay or through test plugs or switches, allows control voltage polarity to be checked before being applied to the relays. Assuming a typical ungrounded DC system, confirm there are no unintentional grounds in the control circuit or battery system.

With grounds or shorts in the control circuit, closing the DC breaker or installing the fuses may trip (or close) a system breaker. In addition, verify that contacts are not wired so their operation results in short circuiting the control bus. After determining that correct polarity for power supplies has been applied and no trip or close paths exist, the sequential functional testing of the devices can begin. The major functional testing steps, along with examples, are discussed below. (Reference Fig. 1, a simplified trip circuit for a circuit breaker)

- Analyze the scheme to plan the test procedures.
- Work sequentially through the scheme. Each step should be structured as an action and an expected result. For example:

- If the DC panel breaker (not shown) is open, then the control bus voltage is zero.

- If the fuses are removed and the DC panel breaker is closed, then polarity and magnitude of the control voltage should be correct at the fuse block.

- If DC is applied to the control bus, then the polarity and magnitude of the control voltage should be correct at the connections for the protective relay power supply.

- After the relay power supply is connected and the DC control bus energized, the relay turns on.

- If this breaker is closed, then (1) the red light should be illuminated and (2) input one (IN1) of the protective relay should be asserted.

- If the control switch (52CS) is moved to the TRIP position, (1) the breaker opens, (2) the red light should be off, and (3) IN1 should be de-asserted.

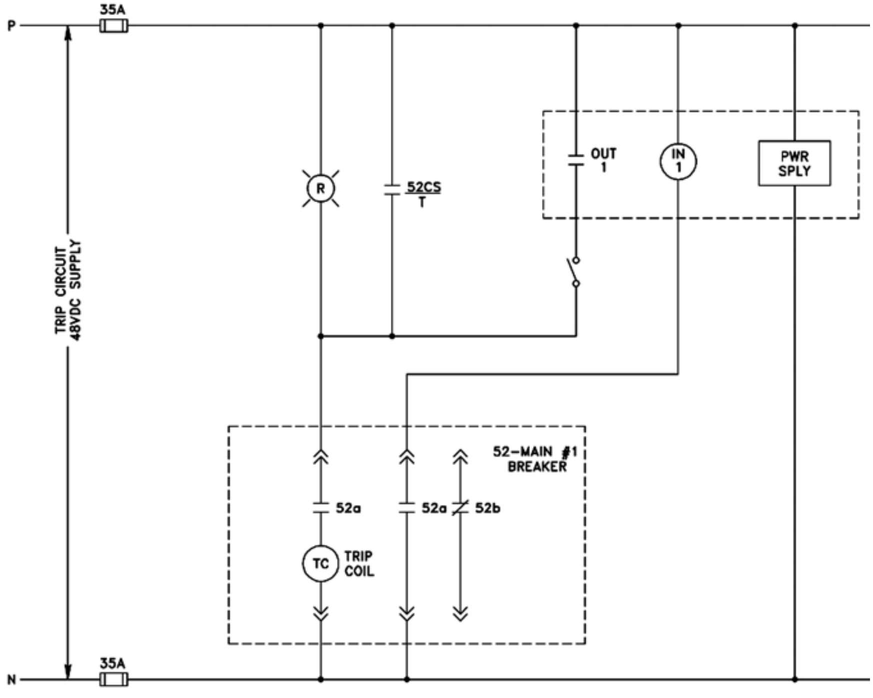

Fig. 1. Simplified DC trip circuit schematic.

- Document the results. Using a highlighter to mark those portions of the control circuit that have been successfully tested is an effective means of documenting the results and forces organization and thoroughness. The cause of failures and unexpected, or confusing results should be determined and corrected before moving on to the next test to avoid compounding problems. Using Fig. 1 as an example, if the breaker is closed and IN1 is not asserted, the problem could be a number of things. Only investigation will reveal whether the wiring is correct, control voltage is present, the relay is damaged, the relay input voltage rating is appropriate, or the breaker auxiliary contact is operating.

By analyzing the scheme to plan the tests, working sequentially through the scheme, and accurately documenting the results, most control logic sequences can be simulated and proper operation verified.

As mentioned in [4], the control and protection flexibility provided by programmable relays and the use of PLCs has made some aspects of start-up and periodic testing more complex. The use of advanced communication systems, control philosophies, multi-function programmable relays, and increased automation and integration, has caused the number of items and systems to be verified to grow immensely. The logic implemented via programmable devices is not visible on the drawings. However, similar procedures, as outlined above, can be adopted to ensure the execution of the programmed logic results in proper operation.

B. CURRENT CIRCUITS

The following items should be verified for current circuits:

- Current transformers (CTs) accuracy class
- CT ratio and polarity (whether marked or not)
- Correct shorting screw removal
- Circuit wiring connections and terminations
- Protective device settings and displays
- Grounding

Many of these items should be tested individually. Accuracy class should be verified during construction and compared against the specifications and drawings. Ratio and Polarity can be tested with a CT test set, or other methods as described in ANSI/IEEE C57.13.1-1981 [2]. The circuit wiring could be “rung-out” to confirm the wiring connections are per the drawings and only one ground exists in the circuit. Device settings and displays, based on the coordination study for the project, are confirmed when testing the protective relays with secondary current injection at the relay panel test plug or switch. However, even though all of these tests are completed, there may still be wiring errors in the CT circuit that can damage equipment or defeat protection. Therefore, the entire current circuit must be checked and settings for CT ratios confirmed before energizing the equipment. After the substation or switchgear is energized, the current circuits, especially differential current circuits, should be rechecked to verify proper phase relationships and connections.

An effective means for testing ratio and polarity for CTs is the voltage method using an oscilloscope, as described in [2] and shown in Fig. 2. An AC voltage, set low enough to not saturate the CT, is applied to the CT secondary and monitored on channel 1 (CH1). The voltage induced on the primary is monitored on channel 2 (CH2). The two signals can then be compared for phase displacement and magnitude. For the connections shown in Fig. 2 the signals should be in phase, confirming polarity, and differ in magnitude by approximately the CT turns ratio. Since inexpensive, dual channel, field duty oscilloscopes are readily available, this method can prove to be more cost effective than using a separate ratio and polarity test set. Note that CTs are typically stamped with the ratio and a polarity mark and have been known to be incorrect.

In order to confirm that the circuit wiring is accurate and programmable device settings in meters and relays are correct, pre-energization tests of the CT circuit wiring should be completed using the procedures for secondary or primary injection from [6]. For the secondary injection test shown in Fig. 3, the variable current source is connected to the first CT terminal block in the circuit. The source is then adjusted until a stable, measurable current is flowing in the circuit. The current is then measured with a clamp-on ammeter at different points in the circuit until reaching the relay or meter case. At that point, it can be confirmed that the wiring is correct for the phase under test. Once the wiring is confirmed, the local and/or remote displays, if equipped, can be checked and the CT ratio setting for the relay or meter confirmed. Note that the connected burden can be calculated with the recorded voltage and current.

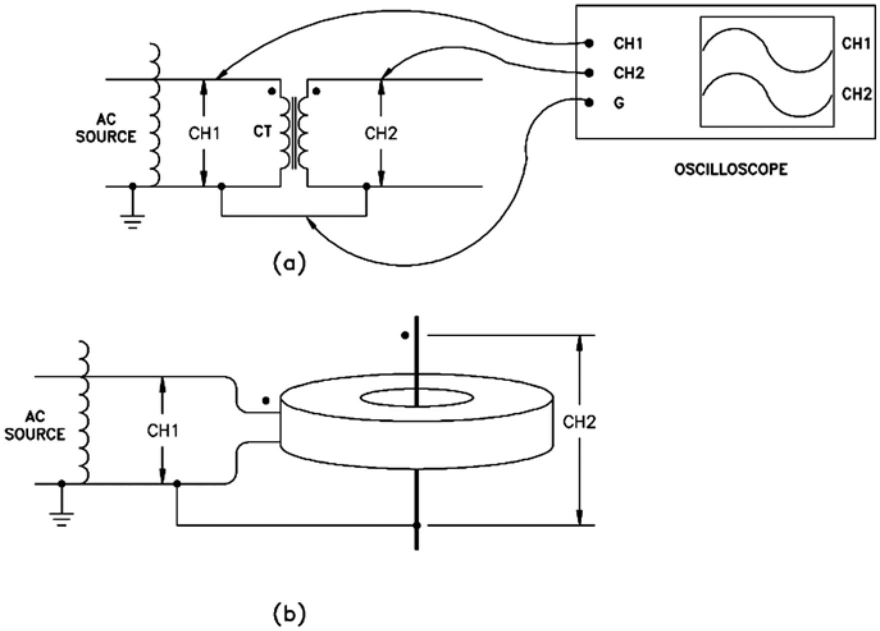

Fig. 2. CT ratio and polarity test. (a) Schematic representation. (b) Physical sketch.

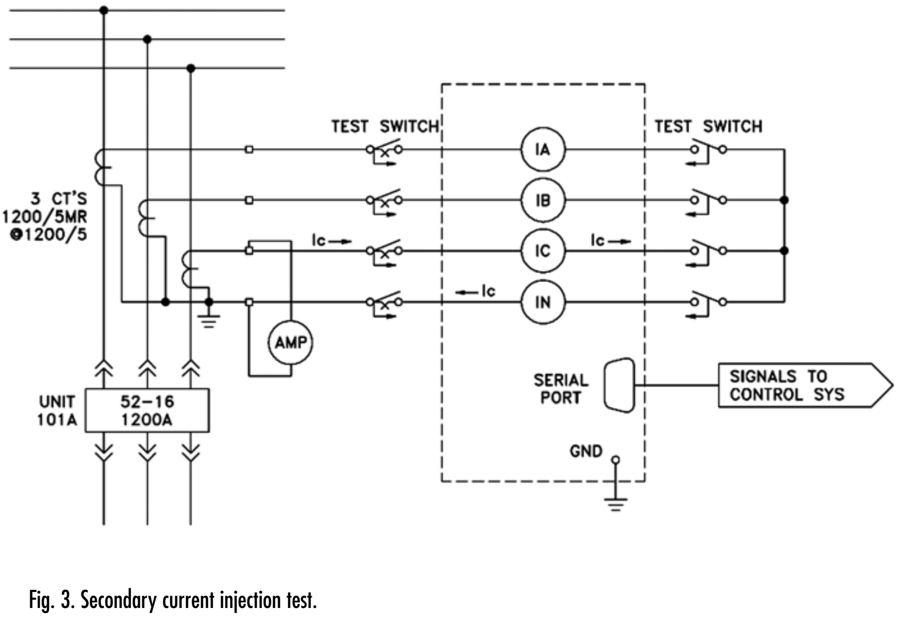

Fig. 3. Secondary current injection test.

C. POTENTIAL CIRCUITS

Potential circuits' ratios, polarity, circuit wiring, device settings and displays, and grounding must be checked similarly to current circuits. The potential transformer (PT) connections should be compared to the drawings. Only after completely isolating the PT, use a variac to apply a secondary voltage.

Proper phase connections to relays and meters as well as any PT ratio settings in programmable devices can then be checked.

The potential transformer secondary fuses must be disconnected to prevent a dangerous high-voltage back-feed.

Several fatalities have been caused by failing to do this on PT and CPT circuits during testing.

By following the procedures outlined above, start-up personnel can be confident the DC control circuits and sensing circuits for the protection scheme are ready for service. Certain items that, in the authors' experience, seem to be overlooked are discussed below.

IV. EXAMPLES OF COMMON OVERSIGHTS

A. ASSUMING FACTORY WIRING IS CORRECT

Often field personnel are forced to assume the factory wiring is correct since verification of all wiring in the field would be too time consuming. Backed by a certified factory test report, the assumption may be valid. In the authors' experience some equipment suppliers are willing to provide certified test reports even though the switchgear has not, in fact, been completely checked.

A major, reputable, switchgear supplier supplied a certified test report for some new equipment. After a number of accessory equipment failures occurred when the authorized factory field service representative began commissioning, the following was discovered:

- A protective relay was damaged due to incorrect wiring in the resistance grounding current circuit.
- Pairs of 120V UPSs for a PLC were destroyed because an auto-transfer scheme was incorrectly wired at the factory.
- One circuit breaker would not charge because the wiring in the cell was incomplete.

According to the factory field service representative, four days were spent trouble-shooting and attempting to determine the cause for the failures. Had factory testing been witnessed to force the supplier to thoroughly test the equipment and provide an honest test report, this time could have been saved and the equipment supplier's reputation with their customer left intact.

B. DC CONTROL CIRCUITS

Common oversights involving DC control circuits include:

- Improper polarity
- Inaccurate wiring
- Improper/Unintentional grounds
- Short circuits
- Assuming all breakers controls are the same

In one facility, the sync-check relay output contact was destroyed twice because incorrect wiring to the relay set up a short circuit of the DC control bus when the output contact closed. The one-week delay for the second replacement relay could have been avoided had a short amount of time been spent to trouble-shoot and correct the circuit.

C. CURRENT CIRCUITS

Common oversights and problems involving current circuits include:

- Shorting screws left in terminal blocks
- Auxiliary CTs installed (wired) "backwards"
- Delta connections in differential circuits
- Protection provided by zero sequence CTs defeated by wiring errors
- Multiple grounds

1) Shorting Screws: Shorting type terminal blocks are normally recommended and supplied for current circuits in order to safely short circuit CT's. All CT circuits typically have shorting screws installed when the equipment is shipped and installed.

These screws are not normally removed until the appropriate devices are connected in the circuit, and they must be left installed for any spare CTs. However, it is a common mistake for shorting screws to be left in terminal blocks in protective device current circuits, defeating the protection.

For example, a petrochemical plant in Southwestern Wyoming placed a substation in service without removing the shorting screws from the CT terminal blocks for the 13.8kV switchgear when the substation was commissioned.

Approximately one year later, a severe snowstorm, accompanied by high winds, forced snow into the tie section of the switchgear. The bus faulted, the switchgear relays did not operate since the CTs were shorted, and finally the 138kV transformer backup relays operated. This fault, finally cleared by the backup protection, caused major damage to the switchgear.

Based on the authors' experience, the most common current circuits that have shorting screws left in the terminal blocks are:

- Capacitor bank balance CTs (three occurrences)
- Neutral CTs in low resistance grounded systems (at least eight occurrences)
- Bus differential CTs (at least six occurrences)

Properly proving out every CT circuit individually, as described above, and documenting the test results on the drawings with a highlighter will prevent this from occurring.

2) Auxiliary Current Transformer Connections: In some instances it may be necessary to use an auxiliary current transformer to either step up or down a current signal. Special care must be exercised to ensure the auxiliary CT is connected correctly, since these CTs are usually installed to increase sensitivity of a protective device. If they are installed incorrectly, they can also defeat the scheme. By analyzing the design, comparing the actual wiring to the drawings and testing the current circuits, proper operation of the protection can be assured.

3) Current Transformer Connections for Transformer Differential Relays: CT connections for differential relay protection of power transformers require consideration of (a) the transformer windings connection – e.g. wye-delta, delta-wye, wye-delta-wye and (b) the differential CTs circuitry to ensure the CTs are connected correctly based on the power transformer connections.

In power transformers, due to the ratio of transformation, the amount of current entering the transformer will differ from that leaving the transformer. If a transformer is connected deltawye, there will also be a phase displacement between the currents. Historically for delta-wye connected transformers, the CT secondary currents are brought into phase by connecting the CTs in wye on the delta side of the power transformer and in delta on the wye side to correct the phase shift, as shown in Fig. 4. The connection shown also helps to avoid zero sequence current problems since a transformer can be a source for zero sequence currents. More recently, some solid-state differential relays posses the means to avoid this problem and the CT's may be connected delta or wye.

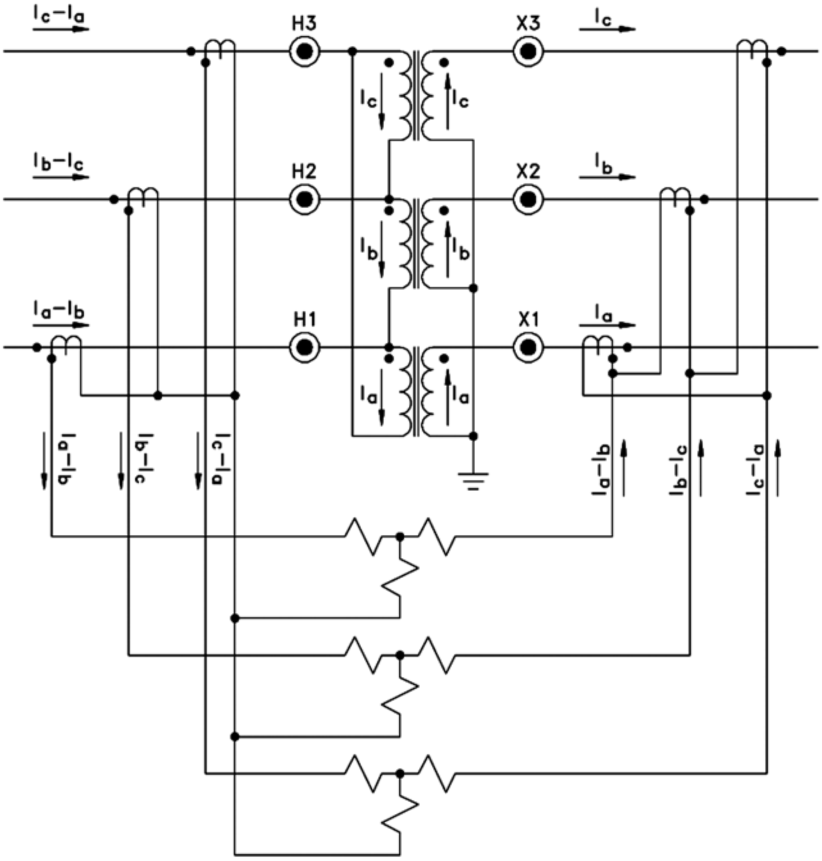

Fig. 4. Differential CT connections for delta-wye transformer.

In many petrochemical plants, power transformers are delta-wye units. The delta connected CTs on the secondary are sometimes incorrectly wired. The result is the transformer is placed in service with incorrect wiring of the differential relay, and false tripping can occur. The false tripping may not occur until a large motor is started or the load in the substation increases to a point sufficient for the relay to falsely operate.

The connections can be verified and this avoided by conducting pre-energization tests per [6] and described in Section III-B Current Circuits. After the drawings have been reviewed and the circuit verified, the primary and secondary differential circuits need to be verified by checking the phase angles and magnitudes of the currents entering the relay with the post-energization load test.

The post-energization load test is the final check that the CTs are connected correctly. The test results are valid only if load current is significantly greater than excitation current when conducting the procedure described below. If the phase angle between the primary voltage and current approaches ninety degrees and the primary to secondary current ratio does not closely match the turns ratio of the power transformer, load must be increased to perform the test. With adequate load on the transformer, the proper phase angle and magnitude of the CT secondary current should be observed at the transformer differential relay connections. A dual channel oscilloscope or an ammeter and phase angle meter can be used for this test. For example, as shown in Fig. 4, the H1 bushing on the power transformer enters a delta winding and consists of the currents (Ia – Ib). In other words, the H1 current has two components, the positive current in winding "a" and the negative current in winding "b". The delta CTs on the secondary of the transformer require this same relationship in making up the delta.

At a petro-chemical plant the authors noticed a discrepancy between the settings on a transformer differential relay and the design engineers request. While investigating the cause, it was discovered the history involved two potentially minor mistakes and one major mistake. The first minor mistake was a drafting error on the AC schematic, which the electricians used to connect the transformer CTs to the differential relay. The second minor mistake occurred when start-up personnel used the same drawing for verification and did not perform pre-energization tests on the CT connections. When the transformer was loaded, the differential relay tripped the unit off-line.

Suspecting an incorrect setting, start-up personnel increased the slope setting until the relay quit tripping, thereby committing the major mistake: The cause of the nuisance trip was not determined and corrected.

4) Core-Balance (Zero Sequence) CTs and Cable: Many installations use a zero sequence CT on their medium-voltage feeders for ground fault detection. However, many times the cable routing and especially the shield or ground wire routing is incorrect. This leads to defeating ground fault sensing or nuisance tripping for faults on other feeders. A properly installed zero sequence CT senses imbalances being carried by the phase conductors, as shown in Fig. 5. If the zero sequence current has a path back through the CT through the cable shields, it will be cancelled out unless the shield wires are passed back through the CT as shown in Fig. 6. (Note: Cable shield current carrying capacity should be compared to available fault current magnitudes when using this type of cable.) This type of error occurs since drawings or connection diagrams rarely show electricians or cable installers how to route cable shields or ground wires. References [7] and [5] provide adequate information for designers, installers, and testing personnel to install these correctly.

Dudor and Padden described one of their experiences in [7] in which nuisance tripping led them to find incorrectly installed core-balance CTs. The authors of this article discovered improperly installed zero sequence CTs at a natural gas plant in Kansas. The facility included 115-13.8kV and 13.8-4.16kV substations, along with 13.8kV and 4.16kV switchgear. The new equipment had been in operation for approximately six months, after being commissioned and started up by the design

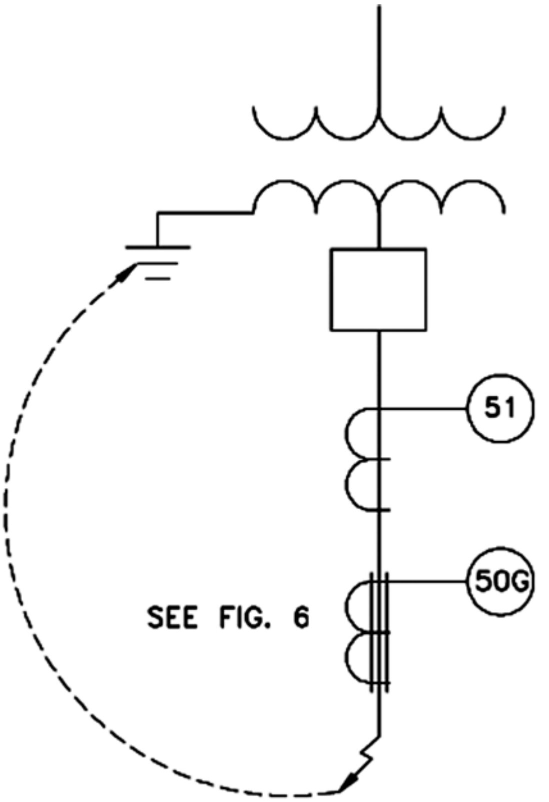

Fig. 5. Ground fault return path outside of core-balance CT.

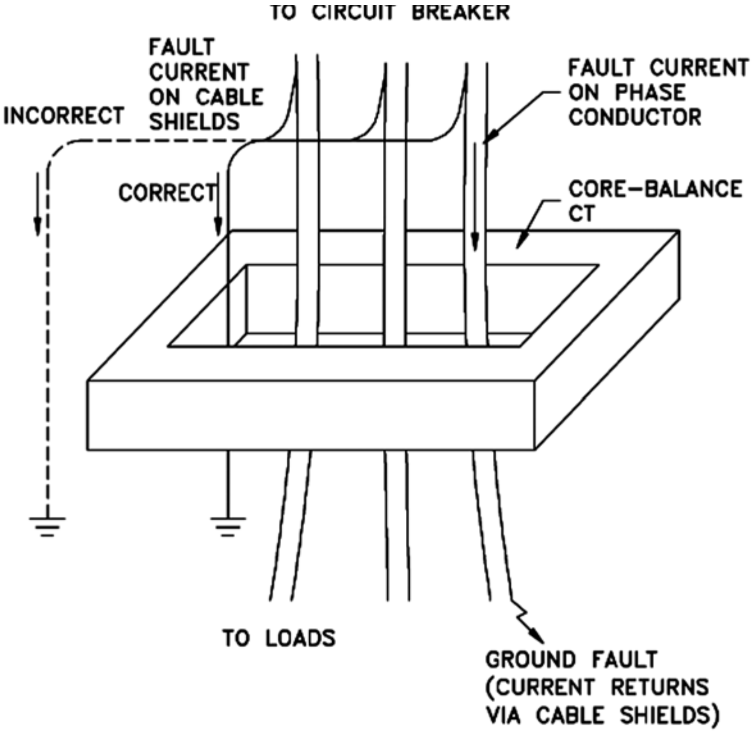
TO CIRCUIT BREAKER
FAULT CURRENT ON CABLE SHIELDS
INCORRECT
CORRECT
FAULT CURRENT ON PHASE CONDUCTOR
CORE–BALANCE CT
TO LOADS
GROUND FAULT (CURRENT RETURNS VIA CABLE SHIELDS)

Fig. 6. Cable and shield routing through core-balance CT.

engineer, equipment manufacturers, and the owner. In two 13.8kV and one 4.16kV feeders for critical equipment, the cable and associated shields were routed through the zero sequence CTs incorrectly. Had a ground fault occurred on these "commissioned" feeders, the fault would have to grow in magnitude or involve other phases before the protection would operate. This plant was fortunate to discover these errors before equipment was destroyed and production time lost.

D. SENSING CIRCUIT GROUNDING

Associated with CT circuits are the grounds. With rare exceptions, only one ground per current circuit should exist. In accordance with [3], the location of this ground "...should be located electrically at one end of the secondary winding of each instrument transformer and physically at the first point of application." The first point of application is typically the relay panel. Often, different personnel will wire different portions of a current circuit and each may elect to place a ground in the circuit. A simple megger test, executed after lifting what should be the only ground, will exclude multiple grounds, avoiding the possibility of circulating currents during fault conditions.

Besides having too many grounds, some tests may require the ground to be lifted from such things as a PT secondary terminal block. When the test is completed, all appropriate connections must be restored. Without the ground connection, meters and relays may not have a ground reference, resulting in inaccurate measurements and a safety hazard. This was the case at a Nevada mill. After using new equipment for over a year, the cause for inaccurate power and voltage readings was traced back to a missing connection between the potential transformers and ground. A testing organization had removed this connection. Fortunately for these operating personnel, the PTs involved were only used for indication and metering so no nuisance trips resulted.

E. SURGE ARRESTER RATINGS

Surge arrester ratings should be verified and compared to the requirements based on the system grounding and all possible operating scenarios that affect grounding. Installation of surge arresters with inadequate Maximum Continuous Operating Voltage (MCOV) ratings on resistance grounded systems seems to occur frequently. Common causes include poor design, being overlooked during the submittal review process, or contractor mistakes. Operating conditions can affect system grounding and therefore change surge arrester rating requirements. For instance, the MCOV rating may be correct for normal system operating conditions, but not for emergencies. Fig. 7 shows a system in which the switchgear can be energized via an ungrounded source. If the emergency generator energizes the switchgear, the delta side of transformer #2 is not grounded. For such a system or for resistance grounded systems, surge arrester MCOV ratings should be based on the line-to-line voltage. If arrester ratings are based on the line-to-neutral voltage and a ground fault occurs, the surge arresters may fail, typically catastrophically on the unfaulted phases.

V. CONCLUSION

Use of lists and procedures outlined in this paper as a starting point for commissioning plans will help avoid having to answer, "How could that have happened?" after an electrical failure.

Qualified people must execute a comprehensive and thorough commissioning plan. The plan should require the correct tests and procedures to save time, verify functionality, and confirm protection will operate as intended, when required.

In particular, qualified personnel should check the following items:

- DC Control Circuits
- Current Circuits
- Potential Circuits
- Equipment Ratings

Start-up and testing services are extremely important. Test results provide a benchmark for future reference while the tests provide verification that the equipment will operate properly.

Failing to properly and thoroughly commission facilities can result in serious and catastrophic consequences with potential for serious injury or death to operating personnel and long down time due to failure of equipment.

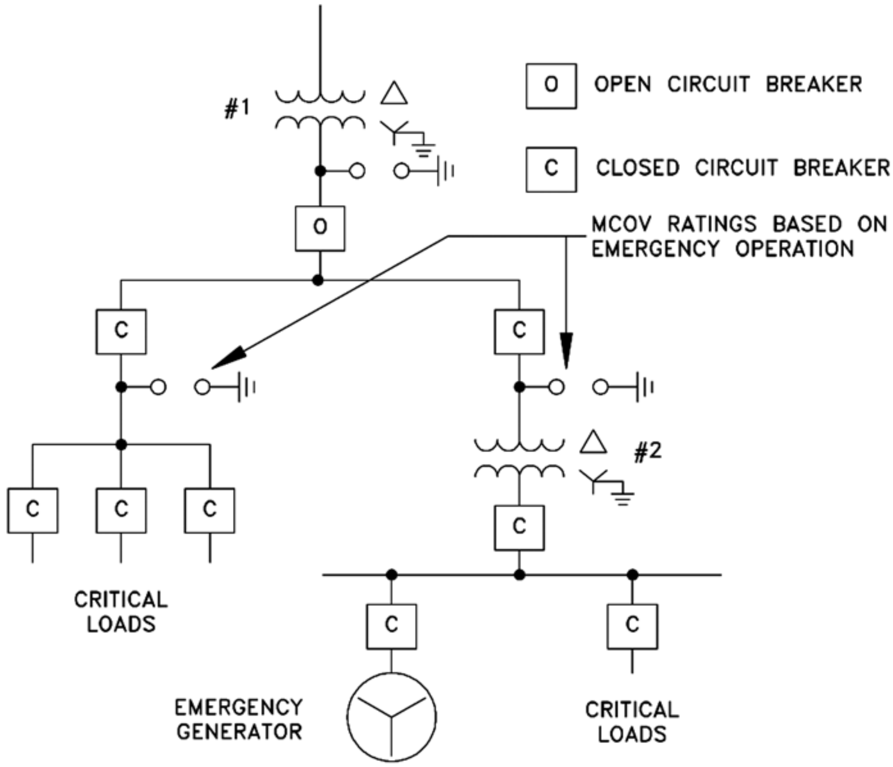

Fig. 7. Operating scenario that dictates surge arrester ratings.

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VII. VITA

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A NEW MEASUREMENT METHOD OF THE DYNAMIC CONTACT RESISTANCE OF HV CIRCUIT BREAKERS

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Fouad Brikci, Zensol Automation Inc. (CANADA)

INTRODUCTION

The design of modern high-voltage puffer-type SF6 gas circuit breakers is based on the switching of two parallel contact sets. First, the low-resistance silver-plated contacts or the main contacts are specifically designed to carry the load current without any excessive temperature rise. Second, following the main contact part, the tungsten-copper arcing contacts are finally opened, thus initiating arc quenching and current interruption.

To assess the condition of the breaker contacts, the main contact resistance measurement is usually performed. However, the static resistance measured when the breaker remains in a closed position does not give any indication of the condition of the arcing contacts. To evaluate the latter's condition, an internal inspection can be done, but time-consuming and costly maintenance procedures must be followed in order to securely handle the SF6 gas and arc by-products. It should be remembered that excessive arcing-contact wear and/or misalignment may result in a decrease of the circuit breaker's breaking capacity.

The dynamic contact resistance measurement (DRM) was developed over 10 years ago to assess the condition of the arcing contacts without dismantling the breaker. This method is no longer widely used since the interpretation of the resistance curve remains ambiguous. Previously published test results usually depicted several spikes [1-3] in the resistance curve which could be the result of a partial contact part during the contact movement.

The following paper presents a new dynamic-contact-resistance measurement method that has been validated by field tests which were performed on air-blast and SF6 gas circuit breakers. The new method is based on the breaker contact resistance measurement during an opening operation at low speed. After reviewing the characteristics of the dynamic resistance curve and the measuring system and parameters, the paper deals with relevant values that can be extracted from the resistance curve for detecting contact anomalies wear and/or misalignment. Finally, case studies are presented and test results are discussed. The new method is available through zensol.com as an accessory of the CBA-32P family test instruments.

1. MEASURING SYSTEM AND SENSORS

For dynamic contact resistance measurements (DRMs), three signals must be recorded:

- the injected current (IDC) of at least 100 A in order to minimize relative noise level;
- the voltage drop (VD) across the breaker contacts;
- the breaker contact travel curve.

Since the new DRM method presented in this paper will be performed during an opening operation at low contact speed when the breaker is off-line, some commercial acquisition units with the following features may be used:

- 3 analog inputs with at least 12-bit resolution and appropriate range of voltage inputs;
- a sampling frequency of W 10 kHz;
- a total acquisition time of 30-100 s;
- connection to a portable computer for calculation of the instantaneous contact resistance (VD/IDC), data analysis and interpretation using dedicated software.

Finally, the following sensors are required:

- Hall-effect current sensor allowing accurate measurement of both the current amplitude and the abrupt current variation at the arcing contact part that corresponds to the complete breaker contact opening;
- linear or rotary contact travel sensor depending upon the breaker technology.

2. MEASURING PARAMETERS

2.1 CLOSING OPERATIONS

DRMs during closing operations are not generally useful since the measurement must be performed during a transient state, i.e. from open to closed contacts. There are two main reasons why the measurement in this condition is impractical:

- the abrupt resistance variation from infinity (open contacts) to the arcing contact resistance is difficult to measure, making the resistance level of the arcing contact difficult to detect;
- the transient DC current at the moment of arcing contact touch generates undesired noise level and therefore jeopardizes the measurement.

2.2 OPENING OPERATIONS AT LOW CONTACT SPEED

DRM should be performed during opening operations at low contact speed (ª 0.002-0.2 m/s). Figure 1a shows superimposed typical resistance curves of two consecutive measurements at rated speed on break A (Table 1). The two traces have been synchronized by superimposing instants of the main contact part which is identified as tm in the Figure 1a graph. Note that no filtering has been applied.

At the rated speed, it can be observed that the resistance curves are not reproducible from one test to another. Moreover, this phenomenon is more marked in the vicinity of the arcing contact part. During the validation test program, it was observed that this behaviour is completely random. On the contrary, for the same breaker A, Figure 1b shows two dynamic contact resistance curves obtained at low contact speeds of 0.2 and 0.15 m/s. The two traces have also been synchronized by superimposing instants of the main contact part. Except for the fact that the curves exhibit different instants of the arcing contact part which are due to measurements at different contact speeds, the two resistance curves appear to be almost identical. To eliminate these time deviations resulting from the contact speed, the dynamic contact resistance may be plotted as a function of the contact travel (section 3.3).

For break B (Table I), Figure 1c depicts another DRM curve that was recorded at the rated contact speed. Several spikes can be observed. Moreover, it is absolutely impossible to identify the main contact part. The presumed main contact part is indicated based on other measurements at low contact speed. As for break A, it is anticipated that this phenomenon is caused by partial contact part due to high contact speed and acceleration. At low contact speed, the DRM curve is far smoother and the main contact part can be easily identified (Fig. 1d).

It must be pointed out that partial contact part does not occur when a high current is interrupted since electromagnetic forces are exerted on the contacts, maintaining them together until final contact separation. Therefore, it is assumed that the low-speed DRM more adequately simulates the actual operating conditions of an in-service HV circuit breaker.

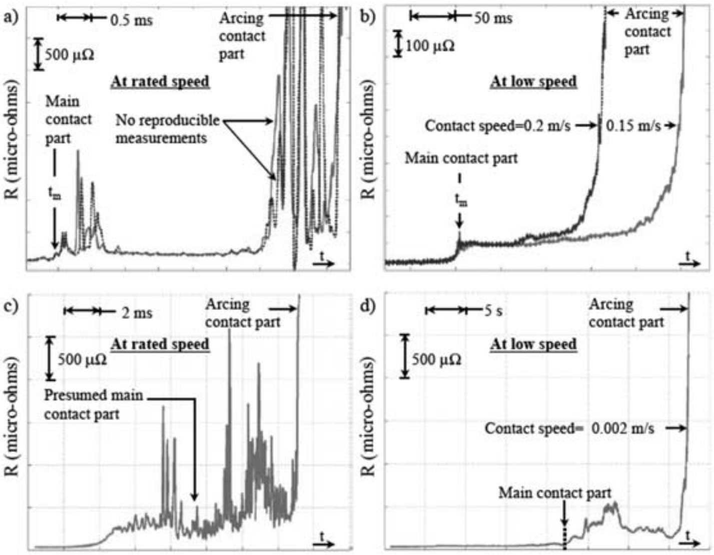

Figure 1 - Comparison of the dynamic contact resistance curves according to the conventional (at rated speed) and the new (at low speed) methods

a) At rated speed on break A b) At low speed on break A
c) At rated speed on break B d) At low speed on break B

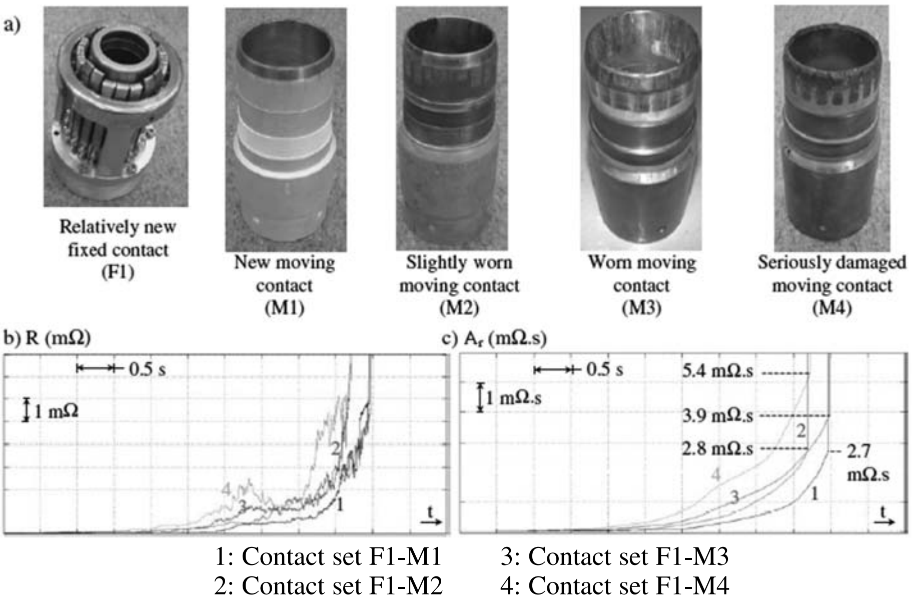

Figure 2 - Wear contact analysis by evaluating the area beneath the dynamic contact resistance curve for different contact sets

a) View of the fixed and moving contacts
b) Graph of the dynamic contact resistance curves
c) Graph of the cumulative area beneath the dynamic contact resistance curves

3. PARAMETERS TO BE EXTRACTED FROM THE DYNAMIC RESISTANCE CURVE

3.1 CONTACT WEAR ALGORITHM

A contact wear algorithm was developed for the new DRM method. Figure 2b depicts the contact resistance curve for different contact sets of an HV air-blast circuit breaker: one relatively new fixed contact (F1) and four moving contacts in different stages of wear (Fig. 2a): a new contact (M1), a slightly worn contact (M2), a worn contact (M3) and a seriously damaged contact (M4), thus forming 4 complete contact sets (F1-M1, F1-M2, F1-M3 and F1-M4). These contact sets were mounted in a laboratory test set-up comprising a vertical computer-numerical-control milling machine, thus allowing the contacts to be closed and opened at a relatively constant and low contact speed. For each contact set, Figure 2c shows the curves of the cumulative area beneath the dynamic contact resistance curves of Figure 2b. The area value (Ar) just before the beginning of the vertical slope corresponds to the maximum value reached just before the arcing contact part. For the different contact sets, the Ar value is:

- 2.7 mW.s for the new contact set F1-M1;
- 2.8 mW.s for the slightly worn contact set F1-M2;
- 3.9 mW.s for the worn contact set F1-M3;
- 5.4 mW.s for the seriously damaged contact set F1-M4.

These Ar values provide an excellent assessment of the actual condition of the contact sets. In fact, the Ar value increases based on contact wear. The seriously damaged contact is clearly identified since the Ar value (i.e. 5.4 mW.s) is twice that for the new contact set (2.7 mW.s).

3.2 GRAPH OF THE CONTACT TRAVEL CURVE AND RESISTANCE CURVE

Figure 3a depicts a typical dynamic resistance curve during an opening operation at low speed where t0 corresponds to

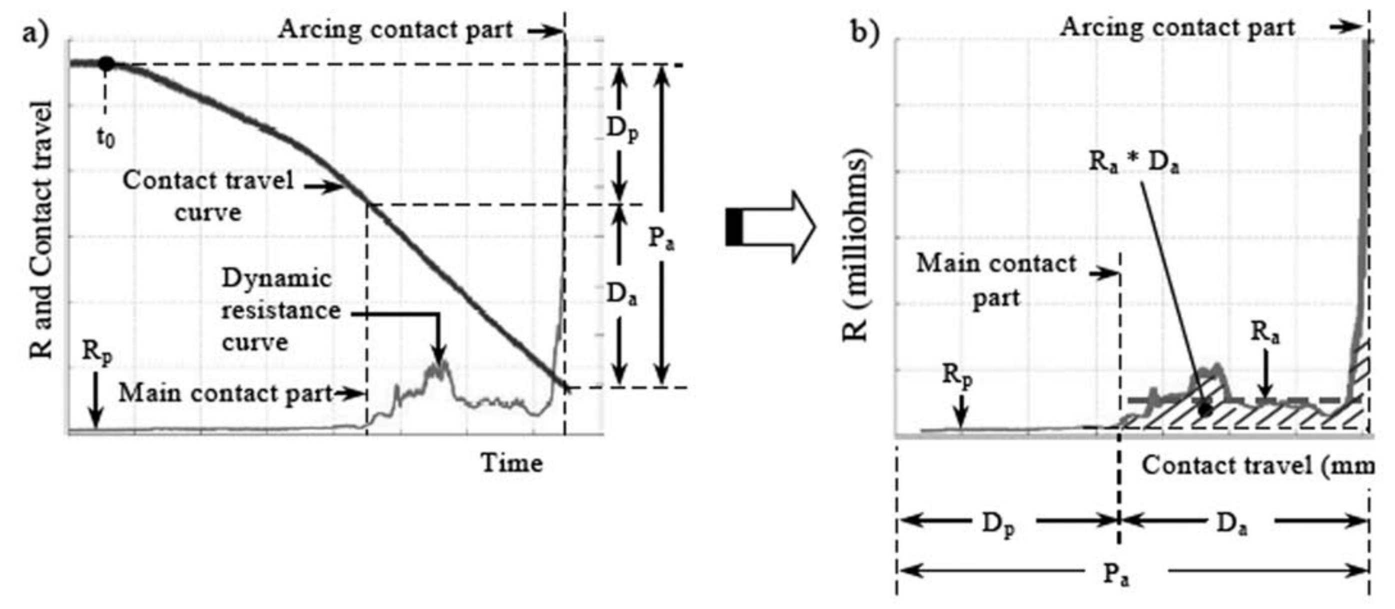

Figure 3 - Parameters to be extracted from the dynamic contact resistance curve
a) Contact resistance and contact motion as a function of time b) Contact resistance as a function of contact travel

the beginning of the breaker contact motion. In most breaker operating manuals, the procedure for performing such a low speed opening is given. It is always relevant to superimpose the travel curve of the breaker contact in order to extract diagnostic parameters related to the position of both the main contacts and the arcing contacts. These parameters are:

- Rp (mW):	Average main contact resistance
- Dp (mm):	Main contact wipe
- Da (mm):	Arcing contact wipe
- Pa (mm):	Position of the breaker contacts at the arcing contact part

3.3 GRAPH OF THE RESISTANCE CURVE AS A FUNCTION OF THE CONTACT TRAVEL

To compensate for the fact that the dynamic resistance curve is measured at a low contact speed that is not necessarily constant for the two test series (Fig. 1a), the contact resistance graph must be plotted as a function of the contact travel (Fig. 3b) in order to evaluate two additional parameters for diagnosing the arcing contact conditions:

- Ra (mW): Average arcing contact resistance = (S Ri=1,N) / N (Fig. 3b), N= Number of samples in the interval Da
- Ra*Da (mW.mm): Area beneath the resistance curve as a function of the contact travel (Fig. 3b)

The latter parameter provides a criterion for evaluating the global breaker contact wear and/or contact alignment status. Once the graph is plotted, all diagnostic parameters can be deduced, including those in section 3.2. Since this graph can be considered as complete for diagnosing the breaker contact condition, it will be given for each case study presented in the following section.

4. CASE STUDIES

The new DRM method was validated in the field on SF6 gas circuit breakers. Three case studies are presented in the following section. Table I summarizes the measurement results for which abnormal values are highlighted.

4.1 CASE STUDY NO. 1: ONE BREAK OF A 315-KV CAPACITOR-BANK SF6 GAS CIRCUIT BREAKER

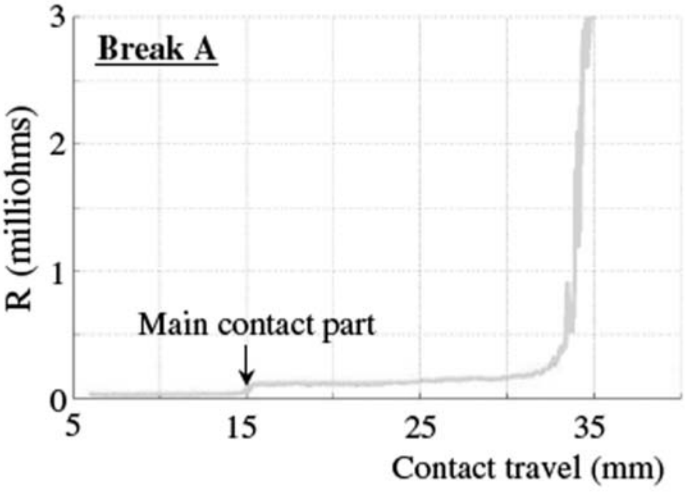

Figure 4 - DRMs on break A

Figure 4 presents the DRM results on a break (Break A, Table I) of a 315-kV capacitor-bank SF6 gas circuit breaker which has performed 2492 operations. Based on this graph and the results listed in Table I, it can be deduced that the arcing contacts are in excellent condition. In fact, the Ra value of 185 mW is almost constant throughout the contact motion. The global criteria Ra*Da is also relatively low, i.e. 3.6 mW.mm. In addition, the main contact part can be easily detected.

Table I – Summary of DRM results

Case study No.	Break description	Operation counter reading	R_p (μΩ)	R_a (μΩ)	D_p (mm)	D_a (mm)	P_a (mm)	R_a*D_a (mΩ.mm)
1 (Fig. 4)	A	2492	29	185	15.1	19.5	34.6	3.6
2 (Fig. 5)	B	687	37	420	21.3	24.6	45.9	10.3
	C (Contact overhaul)	< 20	33	173	30.8	19.7	50.5	3.4
3 (Fig. 6)	D (Internal restrike)	204	74	1763	31.4	34.2	65.7	60.3
	E (Normal break)	201	34	93	33.8	33.5	67.2	3.1

Break A:	Break of a 315-kV capacitor-bank SF6 gas circuit-breaker	Break B:	Break of a 120-kV capacitor-bank SF6 gas circuit-breaker
Break C:	Same as break B, except that arcing contacts were overhauled	Break D:	Break (with internal restrike) of a 230-kV SF6 gas reactor circuit-breaker
Break E:	Same as break D, but without internal restrike		

4.2 CASE STUDY NO. 2: ONE BREAK OF A 120-KV CAPACITOR-BANK SF6 GAS CIRCUIT BREAKER

Case study No. 2 (Fig. 5) presents the DRM results on a break (Break B, Table 1) of a 120-kV capacitor-bank SF6 gas circuit breaker which has performed 687 operations.

In February 2000, a major failure occurred on this circuit breaker which caused important damage to the surrounding equipment. An investigation of the breaker failure revealed that an arcing contact tip appeared to have broken off during an opening operation and thus impaired the subsequent closing operation.

In the fall of 2002, the DRM was performed. Based on the Figure 5a graph, the parameters defined in section 3 were extracted and listed in the case study No. 2 row in Table I. The instantaneous arcing contact resistance reaches an abnormal peak of 1 mW while the average value (Ra) of 420 mW could be interpreted as normal. The most relevant factor is the product Ra*Da that reaches 10.3 mW.mm, thus suggesting a contact anomaly. As mentioned in section 3, this factor represents the cumulative area beneath the resistance curve, thus summing the resistance variations or the contact wear during arcing contact opening.

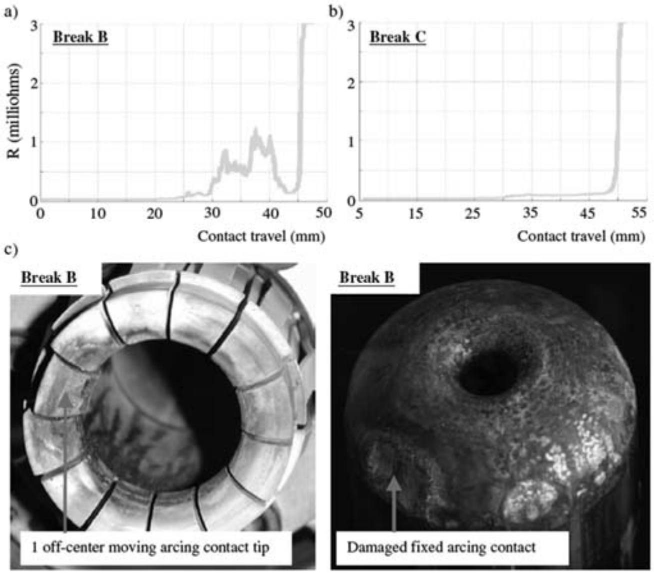

Figure 5 - Dynamic contact resistance measurements on one break of a 120-kV capacitor-bank SF6 gas circuit-breaker
a) Dynamic resistance curve before contact dismantling
b) Dynamic resistance curve after contact overhaul
c) View of the damaged moving and fixed arcing contacts.

Photos of the moving and fixed arcing contacts of the tested break are shown in Figure 5c.

On the moving arcing contact, it can be observed that one arcing contact tip is off center. This abnormality caused damage to the fixed arcing contact (see right-hand side photo). It is believed that this condition occurred due to a misalignment of the arcing contacts at the break assembly. After an arcing contact overhaul and careful contact alignment, the DRM was performed one more time. Figure 5b presents the measurement results that showed that the arcing contact condition was definitely restored. In fact, the Ra value of 173 mW is low. Furthermore, the low Ra*Da value of 3.4 mW.mm indicates that the arcing contact is in excellent condition.

4.3 CASE STUDY NO. 3: ONE BREAK OF A 230-KV REACTOR SF6 GAS CIRCUIT BREAKER

Figure 6a presents the DRM results for break D (Table I) for which an internal breakdown occurred without a major failure. In this case, the Ra value is about 2 mW, which indicates very severe damage to the arcing contacts. The global value Ra*Da of 60 mW.mm is the highest value that was ever obtained during the validation test program. The break was dismantled and arcing traces on both the moving and fixed arcing contacts as well as on the supporting tube of the main contacts were observed.

For comparison purposes, Figure 6b gives the DRM results for a normal break (Break E, Table I) of the same circuit breaker. Based on the curves and the extracted value in Table I, the arcing contacts of this break are clearly in excellent condition. In fact, the Ra value of around 100 mW is almost constant from the main contact part up to the arcing contact part.

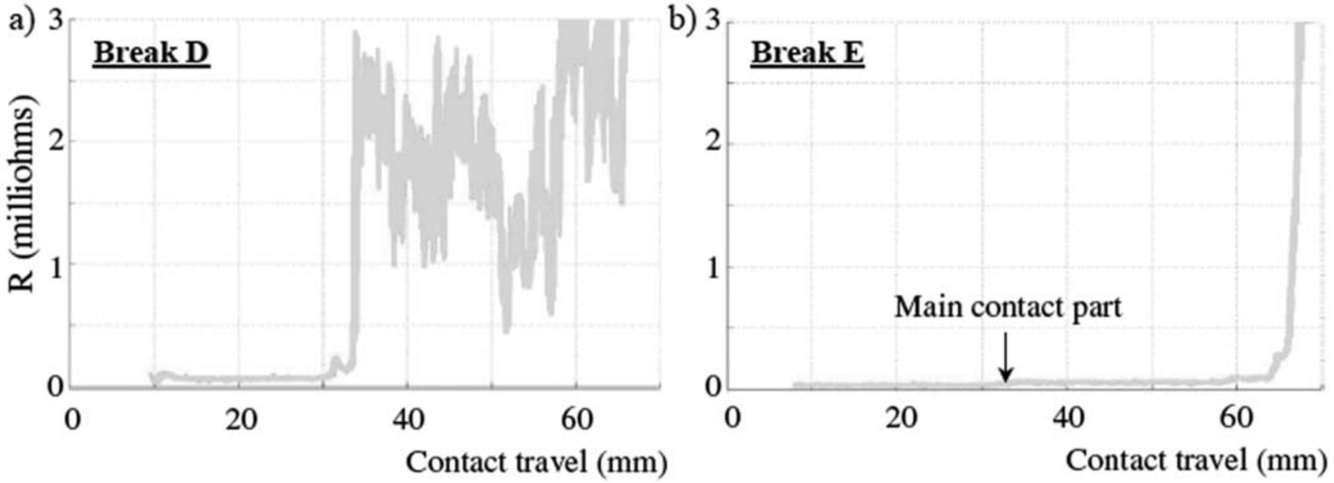

Figure 6 - DRM results on breaks of a 230-kV reactor SF6 gas circuit-breaker: a) Resistance curve following an internal restrike of the break D b) Normal break E

CONCLUSION

This paper presents a new dynamic contact resistance measurement method performed during opening operations at low contact speed aimed at evaluating the breaker condition without dismantling it. Compared to the DRM curves at the rated contact speed, the new method allows reproducible curves to be obtained which are easy to analyze and interpret.

Three signals must be measured: the injected DC current that must be produced by a stable source, the voltage drop across the breaker contacts and the contact travel.

To extract the diagnostic parameters, a dedicated software program was developed in order to plot the dynamic resistance curve as a function of the contact travel, i.e. mW versus mm. Six vital diagnostic parameters values are therefore determined:

- average main contact resistance;
- average arcing contact resistance;
- main contact wipe;
- arcing contact wipe;
- position of the breaker contact at the arcing contact part;
- and the cumulative area beneath the resistance curve.

The last parameter is the most relevant one since it allows the overall contact wear and/or contact alignment status to be assessed. Moreover, values obtained from different breaker technologies can be compared. For example, values of about 3 mW.mm indicate healthy breaker contacts while values of about 10 mW.mm indicate faulty contacts.

The three case studies presented in this paper prove that the new DRM method provides vital information about the breaker contact condition. Without dismantling the breaker, the maintenance crew can thus plan maintenance work for specific breakers for which the DRMs reveal contact anomalies.

Dr. Fouad Brikci is the President of Zensol Automation Inc.. He was the first to introduce the concept of truly-computerized test equipment in the field of circuit breaker analyzers. Dr. Brikci has developed experience in the fields of electronics, automation and computer science.

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DISTRIBUTION SYSTEM FEEDER OVERCURRENT PROTECTION

General Electric

INTRODUCTION

With the increasing loads, voltages and short-circuit duty of distribution substation feeders, distribution overcurrent protection has become more important today than it was even 10 years ago. The ability of the protective equipment to minimize damage when failures do occur and also to minimize service interruption time is demanded not only for economic reasons but also because the general public just expects "reliable" service.

This publication will attempt to review some of the present distribution practices, particularly with regard to relaying, in view of some of these new developments. It is not the purpose of this publication to settle the controversy surrounding some of the problems dealt with, but rather to give the reader a better understanding of distribution overcurrent protection problems and some of the methods being used to solve them.

Among the areas covered will be such things as: coldload pickup, ground-fault detection, tripping methods, current-transformer (CT) connections, line burndown, and coordination between various devices.

RELAY FUNDAMENTALS REQUIRED CHARACTERISTICS

The required characteristics necessary for protective equipment to perform its function properly are: sensitivity, selectivity, speed and reliability. This is especially true for relays.

SENSITIVITY

Sensitivity applies to the ability of the relay to operate reliably under the actual condition that produces the least operating tendency. For example, a time-overcurrent relay must operate under the minimum fault current condition expected. In the normal operation of a power system, generation is switched in and out to give the most economical power generation for different loads which can change at various times of the day and various seasons of the year.

The relay on a distribution feeder must be sensitive enough to operate under the condition of minimum generation when a short circuit at a given point to be protected draws a minimum current through the relay. (NOTE: On many distribution systems, the fault-current magnitude does not differ very much for minimum and maximum generation conditions because most of the system impedance is in the transformer and lines rather than the generators themselves.)

SELECTIVITY

Selectivity is the ability of the relay to differentiate between those conditions for which immediate action is required and those for which no action or a time-delayed operation is required. The relays must be able to recognize faults on their own protected equipment and ignore, in certain cases, all faults outside their protective area. It is the purpose of the relay to be selective in the sense that, for a given fault condition, the minimum number of devices operate to isolate the fault and interrupt service to the fewest customers possible. An example of an inherently selective scheme is differential relaying; other types, which operate with time delay for faults outside of the protected apparatus, are said to be relatively selective. If protective devices are of different operating characteristics, it is especially important that selectivity be established over the full range of short-circuit current magnitudes.

SPEED

Speed is the ability of the relay to operate in the required time period. Speed is important in clearing a fault since it has a direct bearing on the damage done by the short-circuit current; thus, the ultimate goal of the protective equipment is to disconnect the faulty equipment as quickly as possible.

RELIABILITY

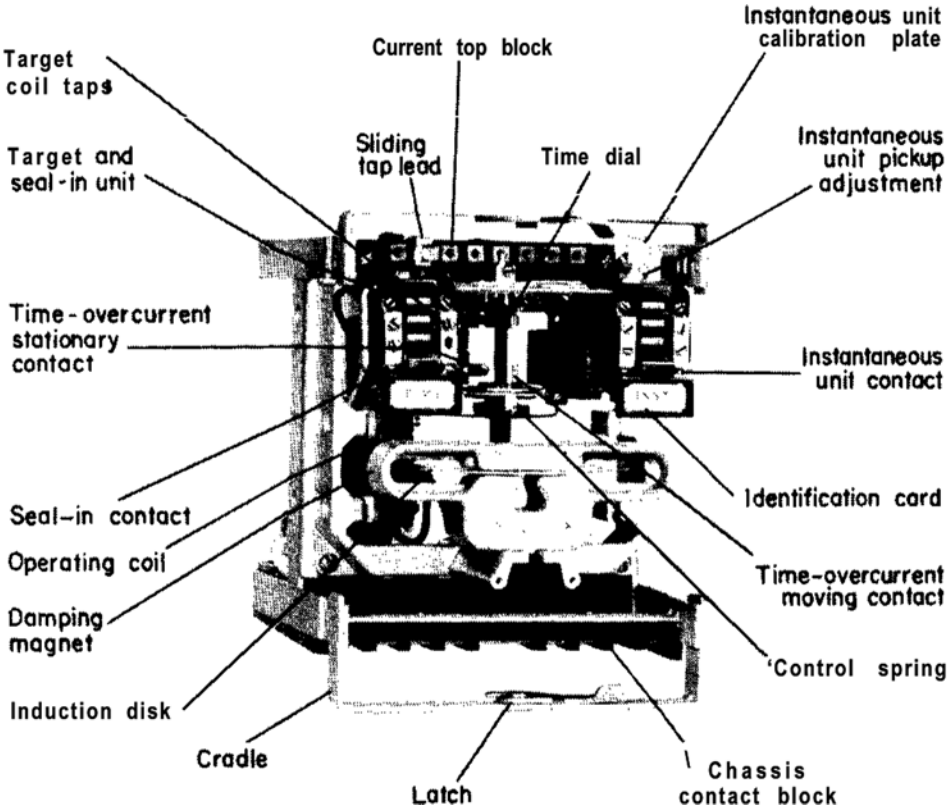
A basic requirement of protective relaying equipment is that it be reliable. Reliability refers to the ability of the relay system to perform correctly. It denotes the certainty of correct operation together with the assurance against incorrect operation from all extraneous causes. The proper application of protective relaying equipment involves the correct choice not only of relaying equipment but also of the associated apparatus. For example, lack of suitable sources of current and voltage for energizing the relay may compromise, if not jeopardize, the protection.

CHARACTERISTICS OF OVERCURRENT RELAYS

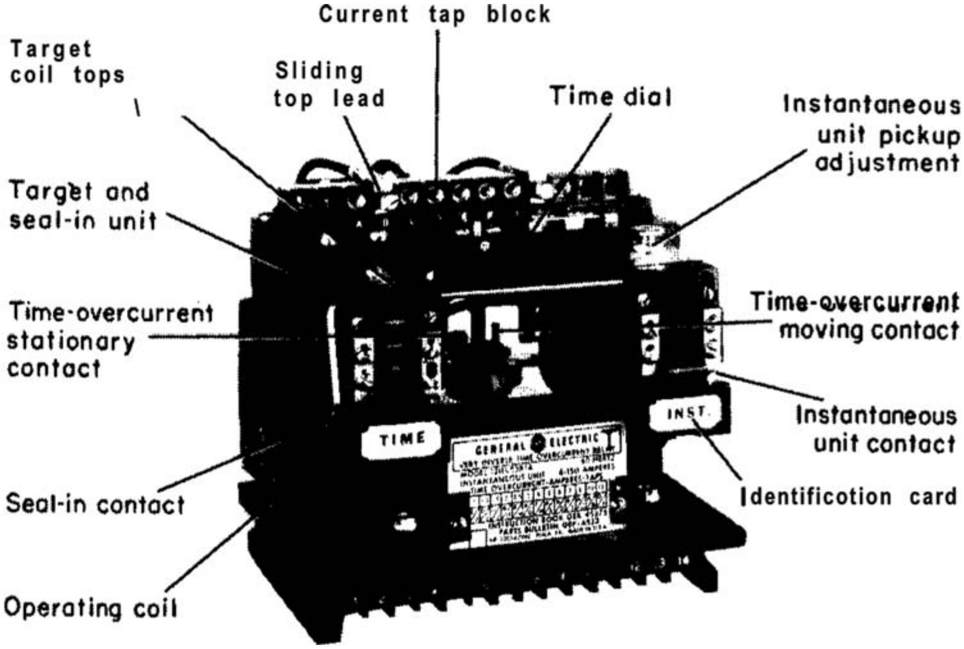
The overcurrent relay is the simplest type of protective relay. (See Fig. 1.) As the name implies, the relay is designed to operate when more than a predetermined amount of current flows into a particular portion of the power system.

There are two basic forms of overcurrent relays: the instantaneous type and the time-delay type.

The instantaneous overcurrent relay is designed to operate with no intentional time delay when the current exceeds the relay setting. Nonetheless, the operating time of this type of relay can vary significantly. It may be as low as 0.016 seconds or as high as 0.1 seconds. The operating characteristic of this relay is illustrated by the instantaneous curve of Fig. 2.



Typical IAC relay mechanism with standard hinged armature instantaneous unit withdrawn from case (Model 72lAC5lB)



Typical IFC relay mechanism with standard hinged armature instantaneous unit withdrawn from case (Model 12lFC53B IA)

Fig. 1. Typical IAC and IFC time-overcurrent relays

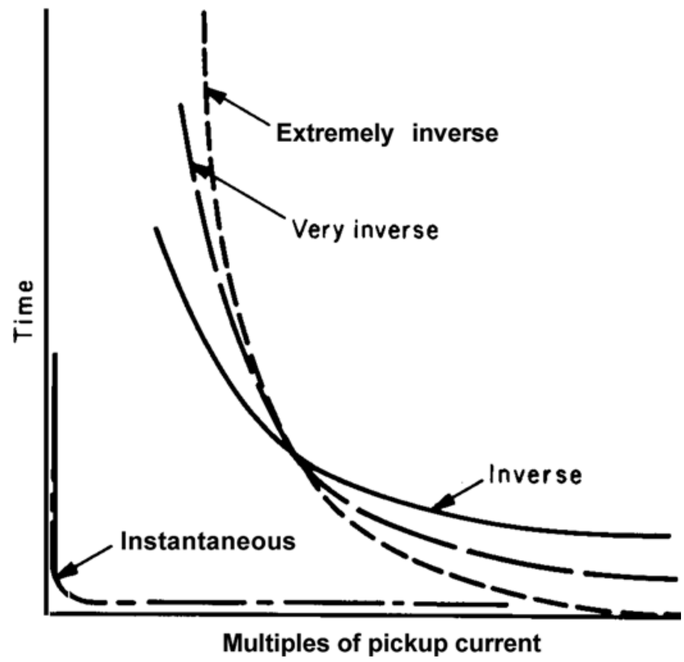


Fig. 2. Time-current characteristics of overcurrent relays

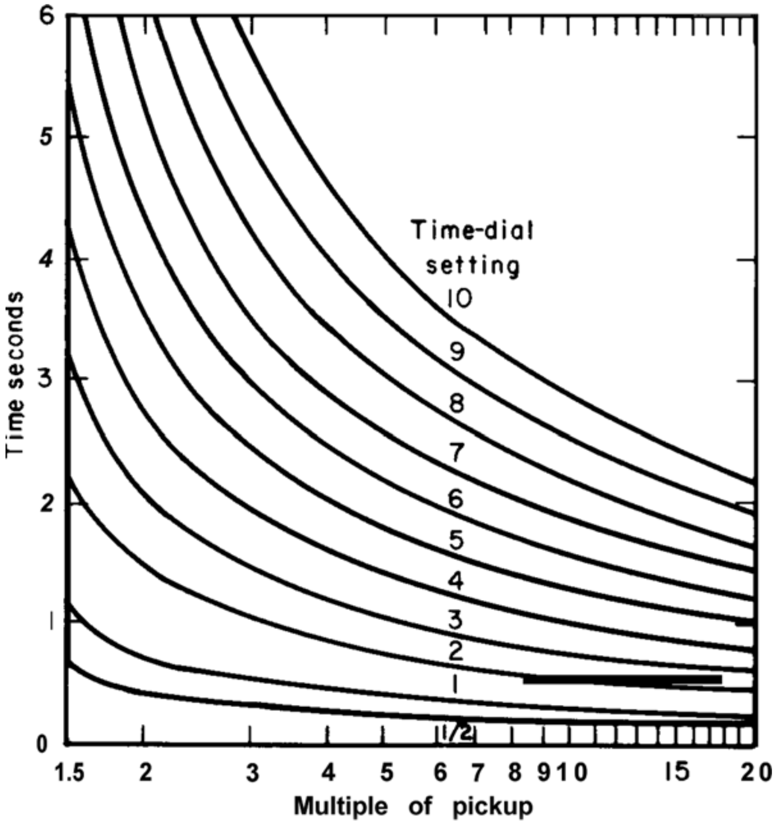


Fig. 3. Inverse time curves

The time-overcurrent relay (IAC, IFC, or SFC) has an operating characteristic such that its operating time varies inversely as the current flowing in the relay. This type of characteristic is also shown in Fig. 2. The diagram shows the three most commonly used time-overcurrent characteristics: inverse, very inverse, and extremely inverse. These curves differ by the rate at which relay operating time decreases as the current increases.

Both types of overcurrent relays are inherently nonselective in that they can detect overcurrent conditions not only in their own protected equipment but also in adjoining equipment. However, in practice, selectivity between overcurrent relays protecting different system elements can be obtained on the basis of sensitivity (pickup) or operating time or a combination of both, depending on the relative time-current characteristics of the particular relays involved. These methods of achieving selectivity will be illustrated later. Directional relays may also be used with overcurrent relays to achieve selectivity.

The application of overcurrent relays is generally more difficult and less permanent than that of any other type of relaying. This is because the operation of overcurrent relays is affected by variations in short-circuit-current magnitude caused by changes in system operation and configuration. Overcurrent relaying in one form or another has been used for relaying of all system components. It is now used primarily on distribution systems where low cost is an important factor.

Figure 3 shows a family of inverse time curves of the widely used IAC relay, which is an induction disc type. The time curves for the new design IFC relay are similar.

A curve is shown for each numerical setting of the time dial scale. Any intermediate curves can be obtained by interpolation since the adjustment is continuous.

It will be noted that the curves shown in Fig. 3 are plotted in terms of multiples of pickup value, so that the same curves can be used for any value of pickup. This is possible with induction-type relays where the pickup adjustment is by coil taps, because the ampere-turns at pickup are the same for each tap. Therefore at a given multiple of pickup, the coil ampere-turns, and hence the torque, are the same regardless of the tap used.

The time-current curves shown in Fig. 3 can be used not only to determine how long it will take the relay to close its contacts at a given multiple of pickup and for any time adjustment, but also how far the relay disc will travel toward the contact-closed position within any time interval.

For example, assume that the No. 5 time-dial adjustment is used and that the multiple of pickup is 3. It will take the relay 2.45 seconds to close its contacts. We see that in 1.45 seconds, the relay would close its contacts if the No. 3 time-dial adjustment were used. In other words, in 1.45 seconds the disc travels a distance corresponding to 3.0 time-dial divisions, or three fifths of the total distance to close the contacts.

For the most effective use of an inverse-time relay characteristic, its pickup should be chosen so that the relay will be operating on the most inverse part of its time curve over the range of values of current for which the relay must operate.

In other words, the minimum value of current for which the relay must operate should be at least 1.5 times pickup, but not very much more.

Figure 4 shows the application of time-overcurrent relays to a radial feeder and the total tripping time characteristics for faults at any location along a circuit. The figure shows the increase in the minimum tripping time as faults occur nearer to the distribution substation - an increase inherent with overcurrent relaying. It also shows the effect of the inverse-time characteristic in reducing this increase.

Obviously, the more line sections there are in series, the greater is the tripping time at the source end. It is not at all unusual for this time to be as high as 2 or 3 seconds. This is not a very long time according to some standards, but it would be intolerable if system stability or line burndown were an important consideration.

During light loads, some of the generators are usually shut down. At other times, the system may be split into several parts. In either case, the short-circuit current tends to vary with the amount of generation feeding it. It should be appreciated that a reduction in the magnitude of shortcircuit current raises all of the characteristic curves of Fig. 4.

For locations where inverse time-overcurrent relays must be mutually selective, it is generally a good policy to use relays whose time-current curves have the same degree of inverseness. Otherwise, the problem of obtaining selectivity over wide ranges of short-circuit current may be difficult.

Instantaneous or undelayed overcurrent relaying is used only for primary relaying to supplement inverse-time relaying and is presently being used by most utilities. It can be used only when the current during short circuit is substantially greater than that under any other possible condition — for example, the momentary current that accompanies the energization of certain system components. The zone of protection of undelayed overcurrent relaying is established entirely by adjustment of sensitivity and is terminated short of the far end of the line. For instance, the instantaneous-overcurrent relay is usually set so that its pickup is 25 percent higher than the maximum current the relay will see for a three-phase fault at the end of the line. With this setting, the instantaneous relay will provide fault protection for about 80 percent of the line section.

Undelayed ("instantaneous") trips can frequently be added to inverse-time relaying and effect a considerable reduction in tripping time. This is shown in Fig. 5 where the two sets of characteristics are superimposed. The time saved through the use of the instantaneous relays is shown by the shaded area. A reduction in the magnitude of short-circuit current shortens the distance over which the instantaneous unit operates and may even reduce this distance to zero.

However, this fact is usually of no great importance since faster tripping under the maximum short-circuit conditions is the primary objective.

Instantaneous tripping is feasible only if there is a substantial increase in the magnitude of the short-circuit current as the short circuit is moved from the far end of a line toward the relay location. This increase should be at least two or three times. For this reason, it often happens that instantaneous relaying can be used only on certain lines and not on others.

On systems where the magnitude of short-circuit current flowing through any given relay is dependent mainly upon the location of the fault to the relay, and only slightly or not at all upon the generation in service, faster clearing can usually be obtained with very-inverse-time-overcurrent relays (IAC 53, IFC 53, or SFC 153). Where the shortcircuit current magnitude is dependent largely upon system-generating capacity at the time of the fault, better results will be obtained with relays having inverse-time operating characteristics (IAC 51, IFC 51, or SFC 151).

However, towards the ends of primary distribution circuits, fuses are sometimes used instead of relays and breakers. In the region where the transition occurs, it is frequently necessary to use overcurrent relays having extremely inverse characteristics (IAC 77, IFC 77 or SFC 177) to coordinate with the fuse characteristics.

The extremely inverse relay characteristic has also been found helpful, under certain conditions, in permitting a feeder to be returned to service after a prolonged outage.

After such a feeder has been out of service for so long a period that the normal "off" period of all intermittent loads (such as furnaces, refrigerators, pumps, water heaters, etc.) has been exceeded, reclosing the feeder throws all of these loads on at once without the usual diversity.

The total inrush current,

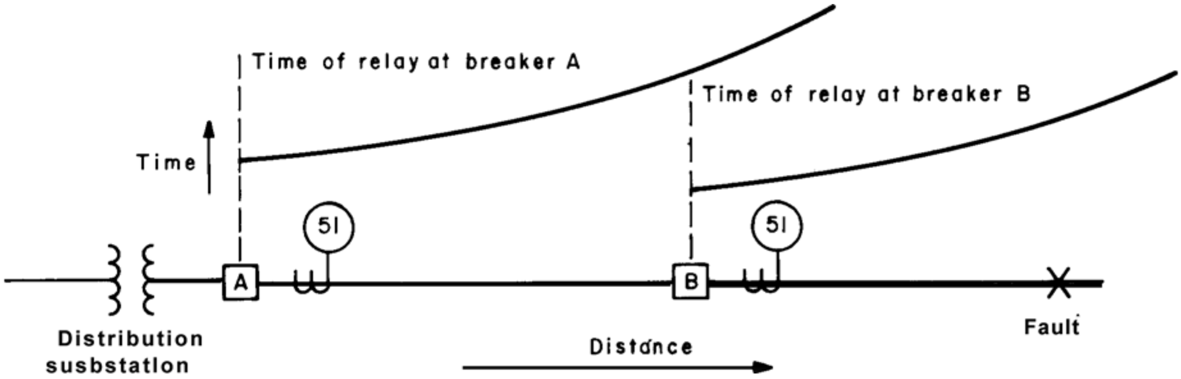


Fig. 4. Operating time of overcurrent relays with inverse time characteristics

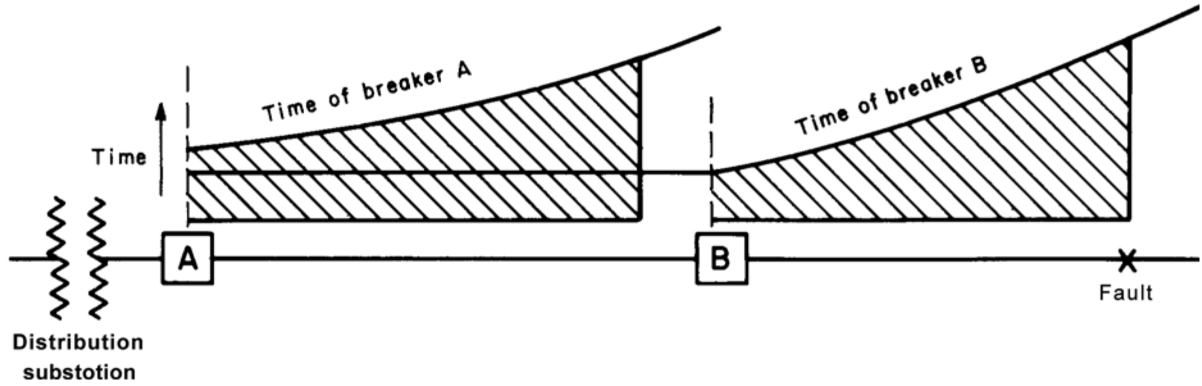


Fig. 5. Reduction in tripping time using instantaneous relaying

also referred to as cold-load pickup, may be approximately four times the normal peak-load current. This inrush current decays very slowly and will be approximately 1.5 times normal peak current after as much as three or four seconds. Only an extremely inverse characteristic relay provides selectivity between this inrush and short-circuit current.

CT CONNECTIONS

A minimum of three overcurrent relays and a total of three current transformers is required to detect all possible faults in a three-phase A-C system. Two of the relays are usually connected in the phase circuits and the third relay is usually connected in the residual circuit of the current transformers as shown in Fig. 6. Sensitive ground-fault protection and protection against simultaneous grounds on different parts of the system is provided by this arrangement whether the system is grounded or ungrounded. On ungrounded systems, current flows in the residual relay when grounds occur on different phases on opposite sides of the current transformer location as indicated in Fig. 6.

On three-phase, four-wire systems (which represent a large percentage of the new installations), it is not always possible to balance perfectly the single-phase loads among the three phases. The use of a sensitive residual ground-overcurrent relay may not be feasible if the relay picks up under normal load conditions. For such systems, the three overcurrent relays are often connected in the phase circuits of the current transformers and the sensitive ground-fault protection sacrificed. An alternative is to use the residual connection of the ground relay in Fig. 6 and to set the pickup of the relay above the maximum expected unbalance phase current.

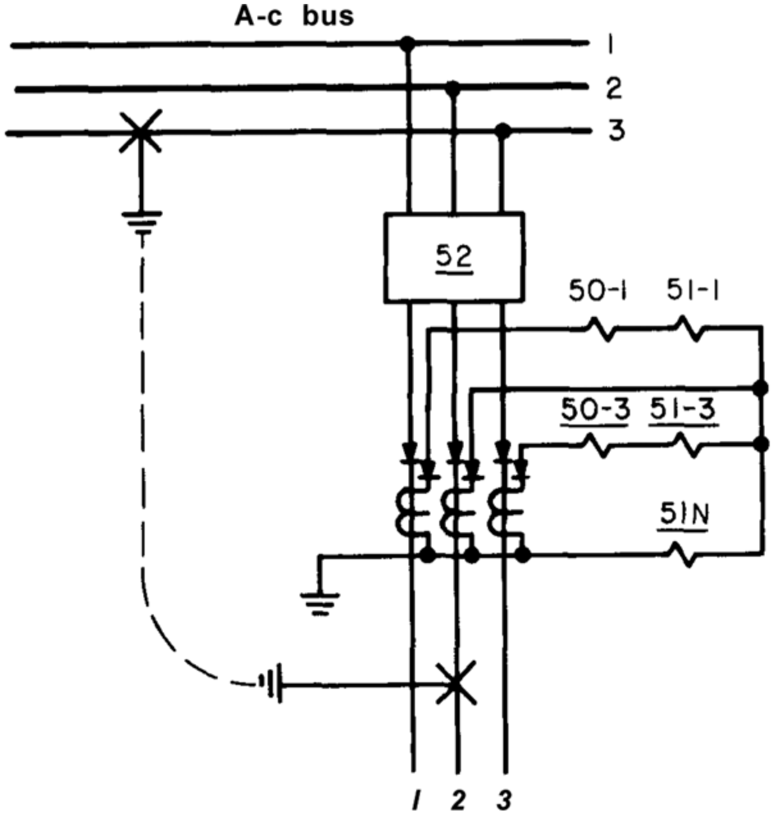


Fig. 6. Elementary diagram of overcurrent relays used for phase- and ground-fault protection of three-phase circuit

It is the practice of some operating companies to block the residual relay to prevent false tripping of the circuit breaker during periods of routine maintenance or when balancing loads on the feeders. This leaves feeders without protection for a line-to-ground fault on the phase without an overcurrent relay, while the residual relay is blocked. It is the usual practice of these companies to request three-phase overcurrent relays in addition to one residual-ground relay for these feeders. This gives complete overcurrent protection to the feeders at all times.

SEAL-IN (OR HOLDING) COILS AND SEAL-IN RELAYS

To protect the contacts from damage resulting from a possible inadvertent attempt to interrupt the flow of the circuit-breaker trip-coil current, some relays are provided with a holding mechanism comprising a small coil in series with the contacts. This coil is on a small electromagnet that acts on a small armature on the moving contact assembly to hold the contacts tightly closed once they have established the flow of trip-coil current. This coil is called the “seal-in” or “holding” coil. Other relays use a small auxiliary relay whose contacts by-pass the protective relay contacts and seal the circuit closed while tripping current flows. This seal-in relay may also display the target. In either case, the circuit is arranged so that, once the trip-coil current starts to flow, it can be interrupted only by a circuit-breaker auxiliary switch (that is connected in series with the trip-coil circuit) and that opens when the breaker opens. This auxiliary switch is defined as an “a” contact.

The circuits of both alternatives are shown in Fig. 7.

TRIPPING METHODS

The substation circuit-breaker tripping power may be from either a D-C or an A-C source. A D-C tripping source is usually obtained from a tripping batttery, but may also be obtained from a station service battery or a charged capacitor.

The A-C tripping source is obtained from current transformers located in the circuit to be protected.

D-C BATTERY TRIP

When properly and adequately maintained, the battery offers the most reliable tripping source. It requires no auxiliary tripping devices, and uses single-contact relays that directly energize a single trip coil in the breaker as shown in Fig. 8. A battery trip supply is not affected by the power-circuit voltage and current conditions during time of faults, and therefore is considered the best source for all types of protective relay tripping. An additional advantage is that only one battery is required for each substation location and it may be used for other equipment; e.g., high-voltage breaker trip circuits and ground switches.

A tripping battery is usually the most economical source of power for tripping a number of breakers. When only one or two breakers are involved, however, it may be more economical to use A-C current or capacitor trip.

Long service can be obtained from batteries when they receive proper maintenance and when they are kept fully charged and the electrolyte is maintained at the proper level and density. When lead-acid batteries are subjected to extremely low ambient temperatures, their output is considerably reduced. In outdoor unit substations, this necessitates larger ampere-hour capacities.

For substations in outlying locations where periodic maintenance is difficult, such as many single-circuit substation applications, other types of tripping sources may be more satisfactory.

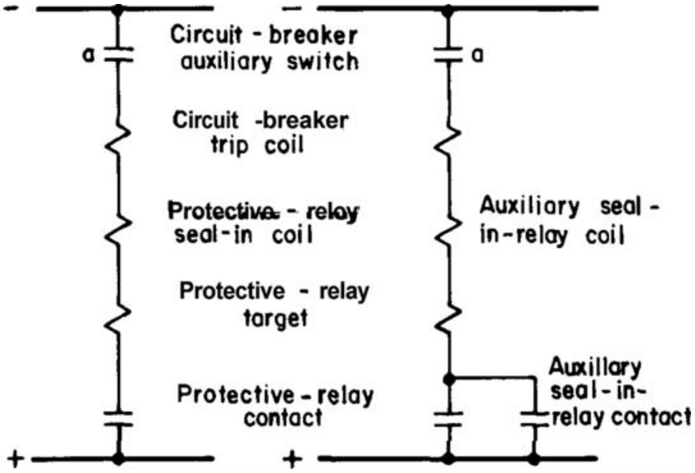
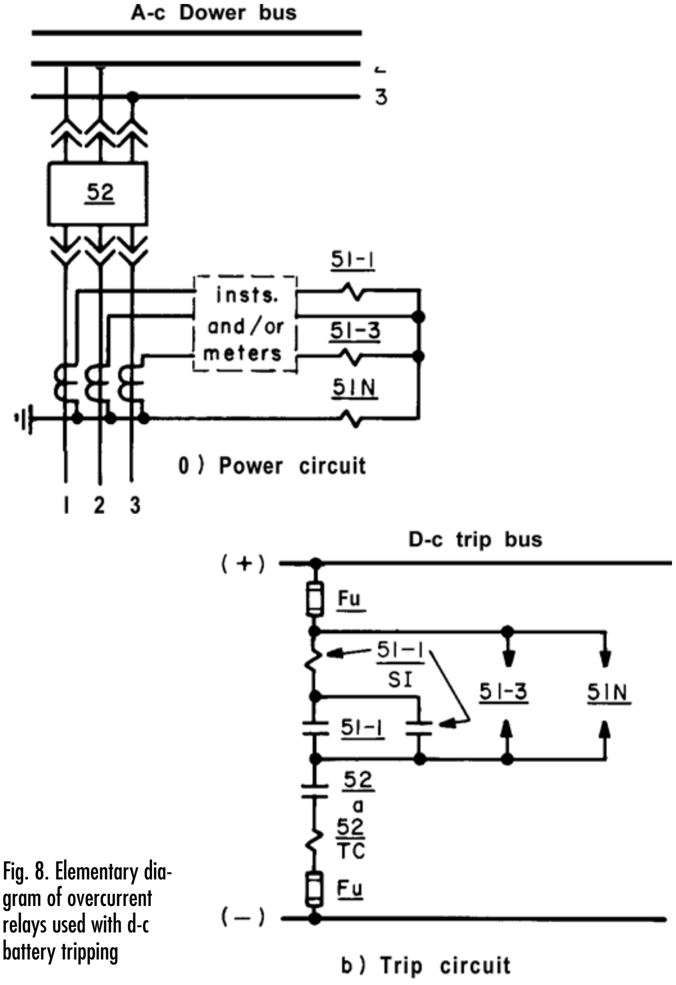

a
Circuit - breaker auxiliary switch
Circuit -breaker trip coil
Protective - relay seal-in coil
Protective - relay target
Protective - relay contact
a
Auxiliary seal - in-relay coil
Auxiliary seal - in-relay contact
-
-
+
+

Fig. 7. Alternative contact seal-in methods



0) Power circuit

b) Trip circuit

Fig. 8. Elementary diagram of overcurrent relays used with d-c battery tripping

CAPACITOR TRIP

An A-C potential source is required for charging the capacitors used in the capacitor trip unit. This source may be either a control power transformer or a potential transformer connected where voltage is normally present. A control power transformer is usually used because it is required for A-C closing of the circuit breakers. Capacitor trip uses the same standard single-closing contact relays as D-C battery trip (see Fig. 9). A separate capacitor trip unit is required for each breaker in the substation. The charging time for the unit is approximately 0.04 second and any failure in the charging source for a period longer than 30 seconds renders the trip inoperative. This time must be factored into time-delay settings of relays.

The capacitor trip unit can be used only with low-energy tripping devices such as the impact trip device used on modern breaker-operating mechanisms. Due to the limited amount of energy available from this device, the breaker must be well maintained to assure successful operation.

This unit provides tripping potential independent of the magnitude of fault current, which makes it particularly applicable on lightly loaded, high-impedance circuits where A-C current trip cannot be used and a battery cannot be justified.

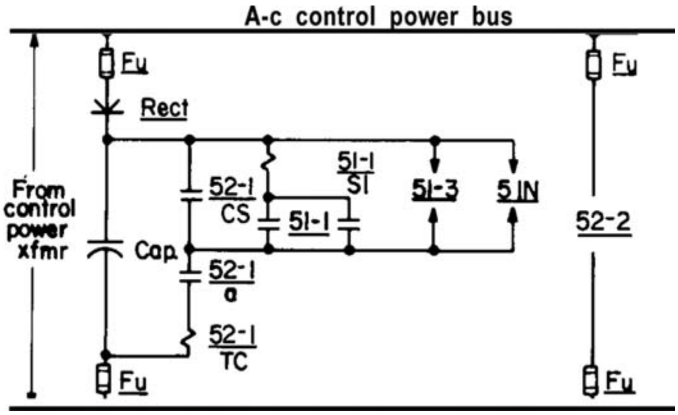


Fig. 9. Elementary diagram of overcurrent relays used with capacitor tripping

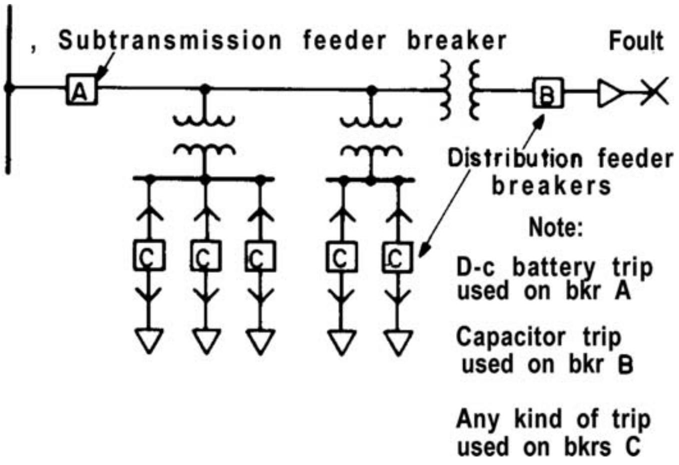

Subtransmission feeder breaker
Foult
A
B
Distribution feeder breakers
C
C
C
C
C
Note:
D-c battery trip used on bkr A
Capacitor trip used on bkr B
Any kind of trip used on bkrs C

Fig. 10. One-line diagram of feeder breaker using capacitor trip with back-up breaker using battery trip

The capacitor trip unit has an additional limitation which is illustrated in Fig. 10. Assume that Breaker A has been open long enough for the capacitor trip unit at Breaker B to become de-energized; further assume that a fault has occurred on the feeder of Breaker B during the time that Breaker A was open. Under these conditions, when Breaker A is reclosed, it will re-energize the feeder of Breaker B on a fault. Due to the fault holding the voltage down, the capacitor may not be charged to provide tripping energy upon closing of the protective relay contacts and backup Breaker A would have to clear the fault. The load fed by Breakers C would be without service until Breaker B was manually tripped and Breaker A was reclosed. However, the probability of such a chain of coincident circumstances occurring is relatively small.

A-C CURRENT TRIP

If adequate current is always available during fault conditions, the current transformers in the protected circuit provide a reliable source of tripping energy which is obtained directly from the faulted circuit. The tripping may be either instantaneous or time delay in operation; but in all cases, it is applicable only to overcurrent protection.

The trip circuit is more complex than for D-C tripping because three trip circuits, complete with individual trip coils and auxiliary devices, are required for each breaker for overcurrent tripping. A potential trip coil is also required for each breaker for normal switching operations. This permits manual tripping of the breaker by means of the breaker control switch.

The three trip coils are normally connected in each phase circuit, rather than two phase coils and one residual coil. This is because adequate trip current may not be available under all ground-fault conditions — e.g., when a ground fault occurs at some distance out on the feeder so that there is sufficient neutral impedance to limit the fault current to a value insufficient to cause tripping, or when applied to a system grounded through a neutral impedance.

A residual relay, which trips the breaker by means of a potential trip coil, is used to provide ground-fault protection under conditions such as these.

A minimum of three or four amperes CT secondary current is required to energize the three-ampere current-trip coils used for this method of tripping. The use of 0.5- to 4.0-ampere range time-overcurrent relays is not recommended because they are more sensitive than the A-C trip coils.

A-C current trip may be by means of reactor trip (circuit-closing relays) or auxiliary relay trip (circuit-opening relays).

The reactor trip method is usually recommended because of its simplicity and because it uses the more standard type overcurrent relays.

APPLICATION CONSIDERATIONS

The choice of the proper source of tripping energy should be based on the application considerations listed here. Any of the foregoing methods are reliable when properly applied; however, each possesses certain advantages and disadvantages. The following general recommendations can be made:

1. Where several breakers are involved and maintenance is good, the storage battery is the most economical. This method also has the added benefit of reliability, simplicity, and ability to be used with all types of protective relays.

2. Where only one or two breakers are used, or maintenance is difficult, one of the other sources could be applied.

a. A-C current trip should be used when adequate current is available.

b. Capacitor trip could be used where adequate trip current is not available.

FEEDER PROTECTION COLD LOAD PICKUP

Whenever service has been interrupted to a distribution feeder for 20 minutes or more, it may be extremely difficult to re-energize the load without causing protective relays to operate. The reason for this is the flow of abnormally high inrush current resulting from the loss of load diversity. High inrush currents are caused by:

1. magnetizing inrush currents to transformers and motors;

2. current to raise the temperatures of lamp filaments and heater elements; and

3. motor-starting current.

Figure 11 shows the inrush current for the first five seconds to a feeder which has been de-energized for 15 minutes. The inrush current, due to magnetizing iron and raising filament and heater elements temperatures, is very high but of such a short duration as to be no problem.

However, motor-starting currents may cause the inrush current to remain sufficiently high to initiate operation of protective relays. The inrush current in Fig. 11 is above 200 percent for almost two seconds.

The magnitude of the inrush current is closely related to load diversity, but quite difficult to determine accurately because of the variation of load between feeders. If refrigerators and deep freeze units run five minutes out of every 20, then all diversity would be lost on outages exceeding 20 minutes.

A feeder relay setting of 200 to 400 percent of full load is considered reasonable. However, unless precautions are taken, this setting may be too low to prevent relay misoperation on inrush following an outage. Increasing this setting may restrict feeder coverage or prevent a reasonable setting of fuses and relays on the source side of this relay.

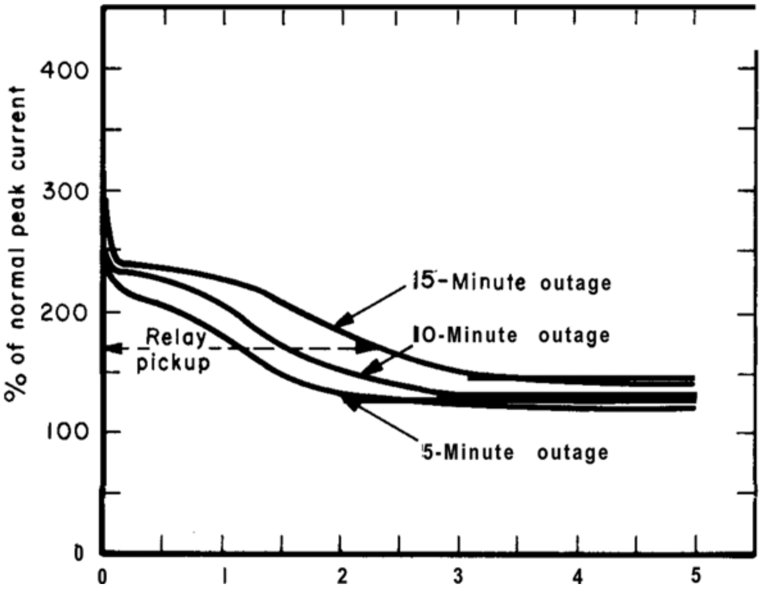


Fig. 11. Five-, ten-, and fifteen-minute outage pickup curves for first five seconds after restoration

A satisfactory solution to this problem is the use of the extremely inverse relay. Figure 12 shows three overcurrent relays which will ride over cold-load inrush. However, the extremely inverse curve is superior in that substantially faster fault-clearing time is achieved at the high-current levels.

This figure, for the purpose of comparison, shows each characteristic with a pickup setting of 200 percent peak load and a five-second time delay at 300-percent peak load to comply with the requirements for re-energizing feeders.

It is evident that the more inverse the characteristic, the more suitable the relay is for feeder short-circuit protection.

The relay operating time, and hence, the duration of the fault can be appreciably decreased by using a more inverse relay. Comparing the inverse characteristic shows that the extremely inverse characteristic gives from 30-cycles faster operation at high currents to as much as 70-cycles faster at lower currents.

Unfortunately, the extremely inverse relay may not always take care of the problem. As the feeder load grows, the relay pickup must be increased and a point may be reached at which the relay cannot detect all faults. At this time, it may be necessary to either move the fuses or reclosers closer to the substation or use automatic sectionalizing.

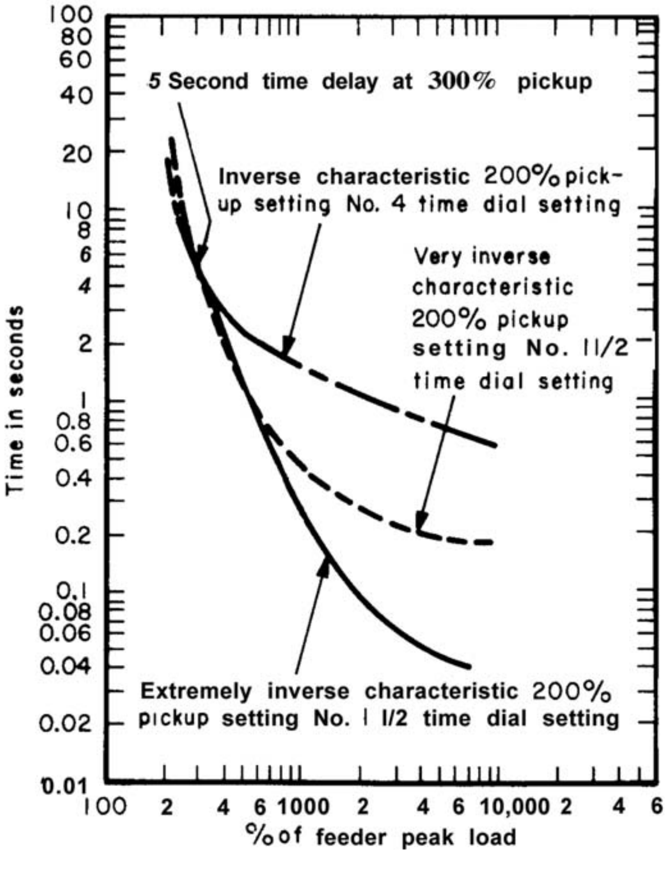


Fig. 12. Comparison of overcurrent relay characteristics

COORDINATION WITH THE TRANSFORMER PRIMARY FUSE

The practice of fusing the distribution substation is controversial.

This is mainly because:

1. the fuse must be replaced every time it blows,

2. the possibility of blowing one fuse and single-phasing three-phase motors exists,

3. the operating time of the fuse must be quite slow so that it coordinates with secondary and feeder breaker relays, and finally

4. the fuse will detect few transformer internal faults since a fault across one-half the winding may be required to cause a fuse to operate.

The fuse must be sized so that it will be able to carry 200 percent of transformer full-load current continuously during emergencies and so that transformer inrush current of 12 to 15 times transformer full-load current can be carried for 0.1 seconds.

Coordination with substation transformer primary fuses requires that the total clearing time of the main breaker (relay time plus breaker interrupting time) be less than 75 percent to 90 percent of the minimum melt characteristics of the primary fuses at all values of current up to the maximum available fault current at the secondary bus.

Figure 13 shows a plot of a 50E fuse which satisfies the inrush and emergency criterion mentioned above and another curve of 75 percent of this minimum melt curve.

To prevent the extremely inverse relay from operating on cold-load pickup, its minimum pickup should not be less than 200 to 250 percent of full-load current. In this case, it will be about 90-amperes primary current. As Fig. 13 shows, the two devices are coordinated only if the maximum secondary fault current is less than 1500 amperes.

If such is not the case, then the size of the fuse must be increased, which in turn limits its transformer-overload protection capabilities.

COORDINATION BETWEEN FEEDER BREAKERS AND THE SECONDARY BREAKER

Coordination between feeder breakers and the transformer secondary breaker requires the total clearing time of the feeder breaker (relay time plus breaker interrupting time) to be less than the relay time of the main secondary breaker by a margin which allows 0.1 seconds for electromechanical relay overtravel plus a 0.1 to 0.3-second factor of safety. This margin should be maintained at all values of current through the maximum fault currents available at the secondary bus.

FAULT SELECTIVE FEEDER RELAYING

The reclosing relay recloses its associated feeder breaker at preset intervals after the breaker has been tripped by overcurrent relays. A recent survey indicates that approximately 70 percent of the faults on overhead lines are nonpersistent.

Little or no physical damage results if these faults are promptly cleared by the operation of relays and circuit breakers. Reclosing the feeder breaker restores the feeder to service with a minimum of outage time.

If any reclosure of the breaker is successful, the reclosing relay resets to its normal position. However, if the fault is persistent, the reclosing relay recloses the breaker a preset number of times and then goes to the lockout position.

The reclosing relay can provide an immediate initial reclosure plus three time-delay reclosures. The immediate initial reclosure and/or one or more of the time-delay reclosures can be made inoperative as required. The intervals between time-delay reclosures are independently adjustable.

The primary advantage of immediate initial reclosing is

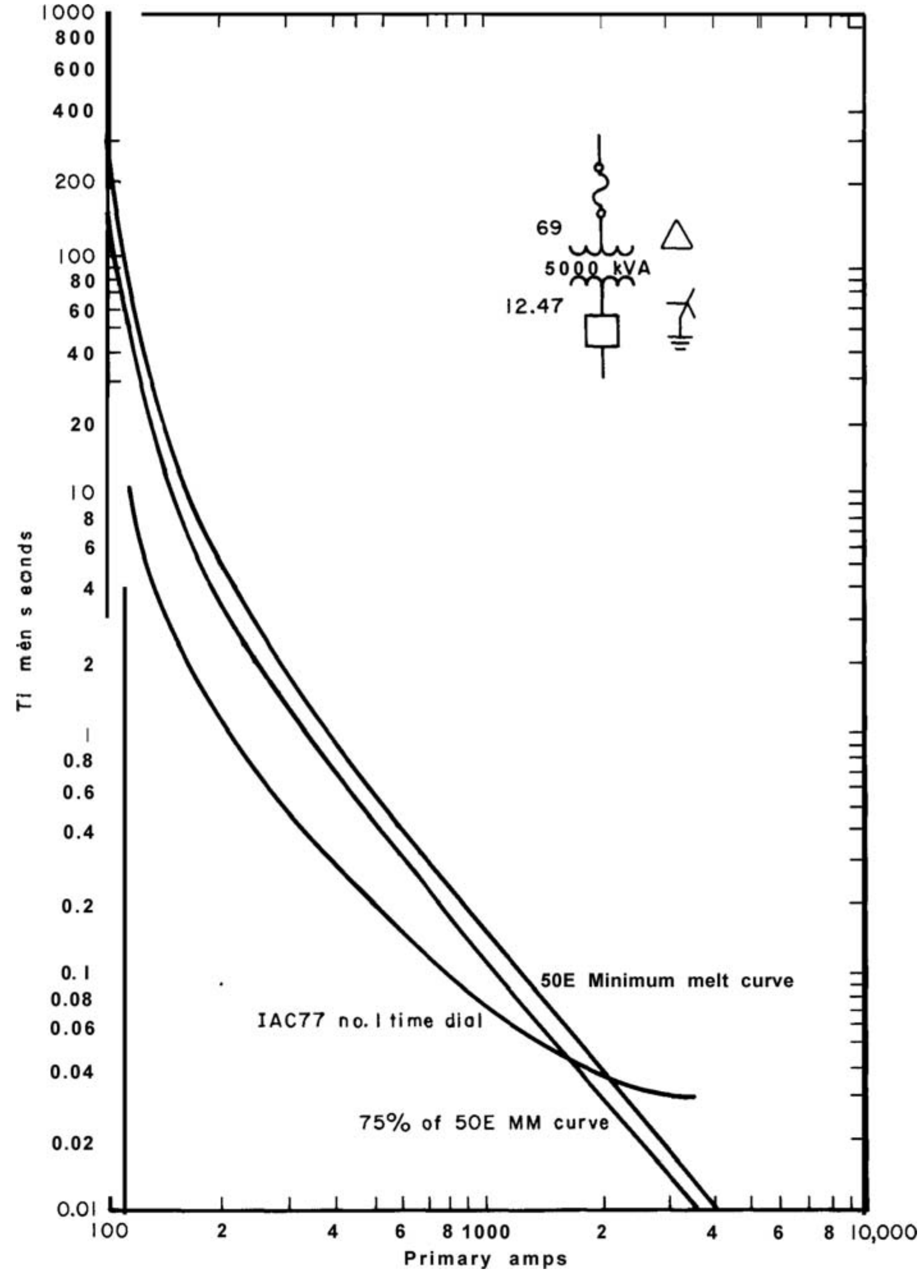


Fig. 13. Plot of a 50E fuse satisfying inrush and emergency criterion

that service is restored so quickly for the majority of interruptions that the customer does not realize that service has been interrupted. The primary objection is that certain industrial customers cannot live with immediate initial reclosing.

The operating times of the overcurrent relays at each end of the tie feeder will be different due to unequal fault-current magnitudes. For this reason, the breakers at each end will trip and reclose at different times and the feeder circuit may not be de-energized until both breakers trip again.

The majority of utilities use a three-shot reclosing cycle with either three time-delay reclosures or an immediate initial reclosure followed by two time-delay reclosures. In general, the interval between reclosures is 15 seconds or longer, with the intervals progressively increasing (e.g., a 15-30-45 second cycle), giving an overall time of 90 seconds.

Fault-selective feeder relaying allows the feeder breaker to clear non-persistent faults on the entire feeder, even beyond sectionalizing or branch fuses, without blowing the 10 fuses. In the event of a persistent fault beyond a fuse, the fuse will blow to isolate the faulty section. Operating engineers report reductions of 65 to 85 percent in fuse blowing on non-persistent faults through the use of this method of relaying.

The feeder circuit-breaker overcurrent relays (No. 150/151) are provided with inverse-time overcurrent tripping and also instantaneous tripping. When a fault occurs, the instantaneous relay (No. 150) trips the circuit breaker before any of the branch-circuit fuses can blow. When the breaker opens, the instantaneous-trip circuit is automatically opened by the reclosing relay (No. 179) and remains open until the reclosing relay has completely timed out the reset (see Fig. 14). If the fault is non-persistent, service to the entire feeder is restored when the breaker recloses, after which the reclosing relay times out to the reset position and the instantaneous trip function is automatically restored.

If the fault is persistent, the circuit breaker recloses on the fault and must trip on the time-delay characteristic since the instantaneous trip is effective only on the first opening. The time-delay trip is adjusted to be slower than the sectionalizing or branch-circuit fuses; consequently, this gives the fuses a chance to blow and isolate the faulted section, leaving the remainder of the feeder in service.

The success of fault-selective feeder relaying depends on proper coordination between the branch-circuit fuses and the feeder-breaker overcurrent relays.

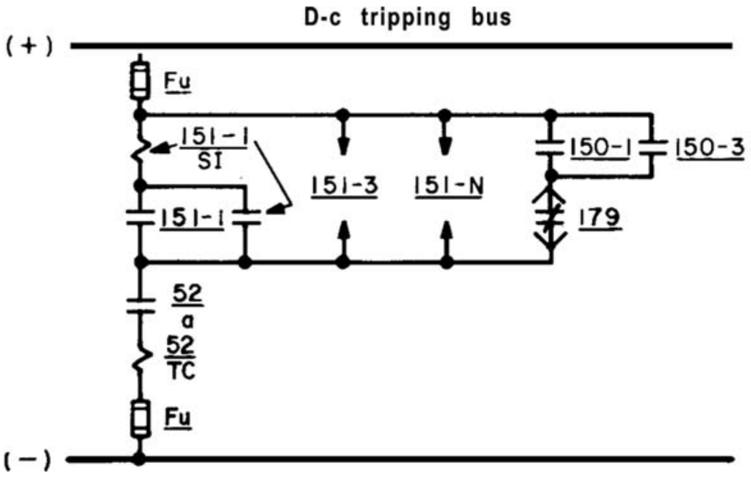


Fig. 14. Elementary diagram of breaker trip circuit showing connections for fault-selective feeder relaying

The feeder breaker, when tripped instantaneously, must clear the fault before the fuse is damaged. Therefore, the breaker-interrupting time plus the operating time of the relay-instantaneous attachment must be less than 75 percent of the fuse minimum-melting current at the maximum-fault current available at the fuse location. In turn, the fuse must clear the fault before the breaker trips on time delay for subsequent operations. Therefore, the total clearing characteristic of the fuse must lie below the relay characteristic at all values of current up to the maximum current available at the fuse location. The margin between the fuse and relay characteristics must include a safety factor of 0.1 to 0.3 second plus 0.1 second for relay overtravel.

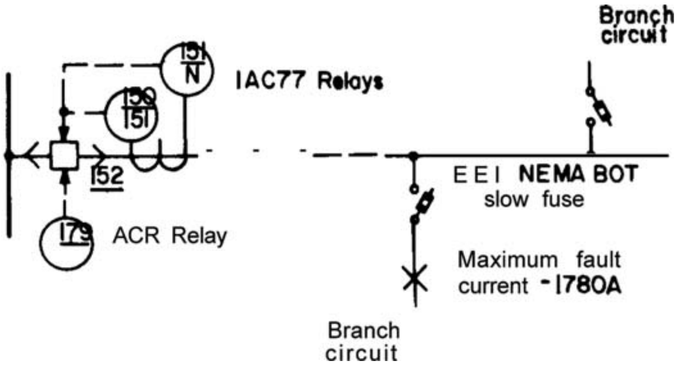


Fig. 15. One-line diagram of typical feeder circuit protected by fault-selective feeder relaying

An example of fault-selective feeder relaying is illustrated in Figs. 15 and 16. The one-line diagram of the feeder circuit is shown in Fig. 15 and the coordination curves are shown in Fig. 16. The overcurrent relay (No. 150/151) has an extremely inverse characteristic (No. 151) with a pickup setting of 480 amperes and 1-1/2 time-dial setting. The instantaneous element (No. 150) has a pickup setting of 600 amperes. The EEI-NEMA 80T (slow) fuse is the largest "slow" fuse which will coordinate with this combination of relay characteristics and settings. At 1780 amperes, the time delay of the relay-instantaneous element, plus the breaker-interrupting time, are just equal to 75 percent of the fuse minimum-melting time. At this same current magnitude, the fuse total clearing time is less than the relay time-delay characteristic by a suitable margin. Therefore, the fuse and relay co-ordinate for current magnitudes of 1780 amperes or less.

For certain applications, the maximum available fault current will exceed the maximum current which will permit coordination. There are two reasons for this:

1. the maximum current for co-ordination is lower for lower-rated fuses and is also lower for Type K (fast) fuses, and

2. fault currents may be quite high at fuse locations comparatively near the substation.

Of course, if the branch circuit is single phase, it is only necessary to consider the maximum line-to-line or line-to-ground fault current, both of which are less than the maximum three-phase fault current. For such applications, coordination can be relied upon only when there is sufficient additional impedance to limit the fault current to the maximum current which will permit coordination. This additional impedance can either be in the fault itself or in the branch circuit between the fuse and the fault location.

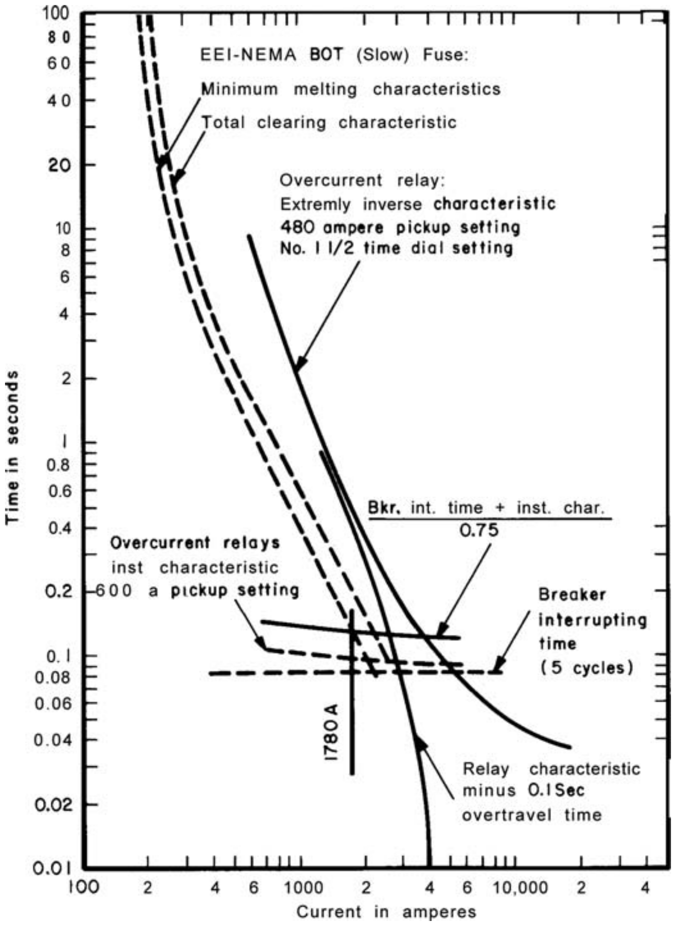


Fig. 16. Coordination of relay and fuse characteristics for fault-selective feeder relay

Therefore, while coordination will be questionable for faults near the fuse, there will be complete coordination for faults which occur father out on the branch circuit.

COORDINATION OF FEEDER RELAYS AND RECLOSERS

If a permanent fault occurs anywhere on the system beyond a feeder, the recloser device will operate once, twice, or three times instantaneously (depending upon adjustment) in an attempt to clear the fault. However, since a permanent fault will still be on the line at the end of these instantaneous operations, it must be cleared away by some other means. For this reason, the recloser is provided with one-, two-, or three-time delay operations (depending upon adjustment). These additional operations are purposely slower to provide coordination with fuses or allow the fault to "self clear". After the fourth opening, if the fault is still on the line, the recloser will lock open.

Figure 17 represents the instantaneous-and time-delay characteristics of a conventional automatic circuit recloser.

At substations where the available short-circuit current at the distribution feeder bus is 250 MVA or more, the feeder circuits are usually provided with circuit breakers and extremely inverse-time overcurrent relays. The relays of each feeder should be adjusted so that they can protect the circuit to a point beyond the first recloser in the main feeder but with enough time delay to be selective with the recloser during any or all of the operations within the complete recloser cycle.

An important factor in obtaining this selectivity is the reset time of the overcurrent relays. If, having started to operate when a fault occurs beyond the recloser, an overcurrent relay does not have time to completely reset after the recloser trips and before it recloses (an interval of approximately one second), the relay may "inch" its way toward tripping during successive recloser operations. Thus it can be seen that it is not sufficient merely to make the relay time only slightly longer than the recloser time.

It is a good "rule of thumb" that there will be a possible lack of selectivity if the operating time of the relay at any current is less than twice the time-delay characteristic of the recloser. The basis of this rule, and the method of calculating the selectivity, will become evident by considering an example.

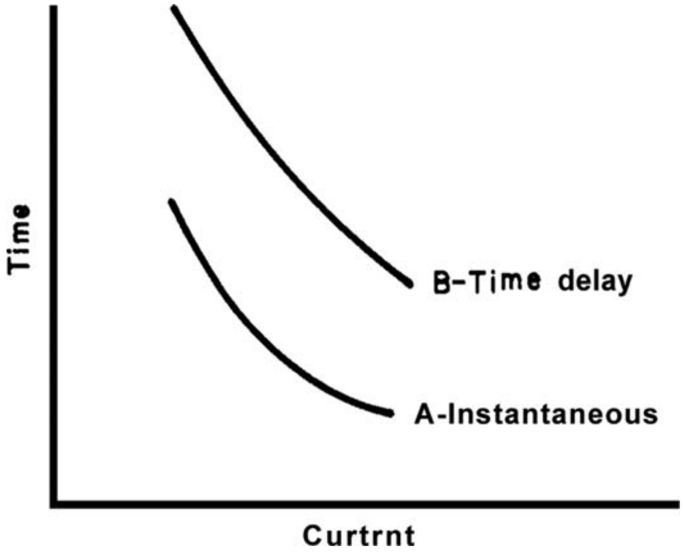


Fig. 17. Tripping characteristic for conventional automatic circuit recloser

First, it should be known how to use available data for calculating the relay response under conditions of possibly incomplete resetting. The angular velocity of the rotor of an inverse-time relay for a given multiple of pickup current is substantially constant throughout the travel from the reset (i.e., completely open) position to the closed position where the contacts close. Therefore, if it is known (from the time-current curves) how long it takes a relay to close its contacts at a given multiple of pickup and with a given time-dial adjustment, it can be estimated what portion of the total travel toward the contact-closed position the rotor will move in any given time. Similarly, the resetting velocity of the relay rotor is substantially constant throughout its travel. If the reset time from the contact-closed position is known for any given time-delay adjustment, the reset time for any portion of the total travel can be determined. The reset time for the longest travel (when the longest time-delay adjustment is used) is generally given for each type of relay. The re-set time for the number 10 time-dial setting is approximately six seconds for an inverse Type IAC relay, and approximately 60 seconds for either a very inverse or any extremely inverse Type IAC relay.

The foregoing information may be applied to an example by referring to Fig. 18. Curves A and 8 are the upper curves of the band of variation for the instantaneous and time-delay characteristics of a 35-ampere recloser. Curve C is the time-current curve of the very inverse Type IAC relay set on the number 1.0 time-dial adjustment and 4-ampere tap (160-ampere primary with 200/5 current transformers).

Assume that it is desired to check the selectivity for a fault current of 500 amperes. It is assumed that the fault will persist through all of the reclosures. To be selective, the IAC relay must not trip its breaker for a fault beyond the recloser.

The operating times of the relay and recloser for this example are:

Recloser:
Instantaneous - 0.036 second
Time delay - 0.25

Relay:
Pickup - 0.65 second
Reset - (1.0/10)(60) = 6.0 second

The percent of total travel of the IAC relay during the various recloser operations is as follows, where plus means travel in the contact-closing direction and minus means travel in the reset direction:

Recloser Operation	Percent of Total Relay Travel
First instantaneous trip (0.036/0.65)	x (100) = + 5.5
Open for one second (1/6)	x (100) = -16.7

It is apparent from this that the IAC relay will completely reset while the recloser is open following each instantaneous opening.

Recloser Operation	Percent of Total Relay Travel
First time-delay trip	(0.25/0.65) x (100) = +38.5
Open for one second	(1/6) x (100) = -16.7
Second time-delay trip	(0.25/0.65) x (100) = +38.5

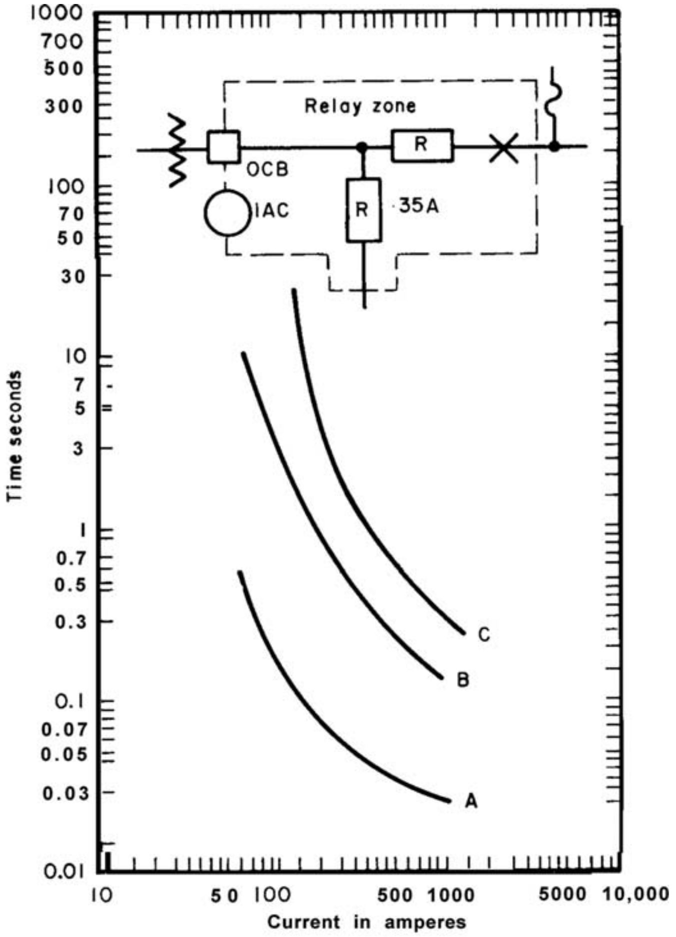
From this analysis, it appears that the relay will have a net travel of 60.3 percent of the total travel toward the contact-closed position.

From the foregoing, it is seen that the relay travel lacks approximately 40 percent (or 0.4 x 0.65 = 0.24 second) of that necessary for the relay to close its contacts and trip its breaker. On the basis of these figures, the IAC will be selective. A 0.15- to 0.2-second margin is generally considered desirable to guard against variations from published characteristics, errors in reading curves, etc. (The static overcurrent relay Type SFC, overcomes some of these problems since the overtravel of such a relay is about 0.01 seconds and the reset time is 0.1 seconds or less.)

If the automatic circuit reclosers are used at the substation as feeder breakers, it is necessary to select the proper size to meet the following conditions:

1. The interrupting capacity of the recloser should be greater than the maximum calculated fault current available on the bus.

2. The load-current rating (coil rating) of the recloser



A. Time-current characteristic of one instantaneous recloser opening
B. Time-current characteristic of one extended timedelay recloser opening
C. Time-current characteristic of the IAC relay

Fig.18. Relay-recloser coordination

should be greater than the peak-load current of the circuit.

It is recommended that the coil rating of the recloser be of sufficient size to allow for normal load growth and be relatively free from unnecessary tripping due to inrush current following a prolonged outage. The margin between peak load on the circuit and the recloser rating is usually about 30 percent.

3. The minimum pickup current of the recloser is two times (2X) its coil rating. This determines its zone of protection as established by the minimum calculated fault current in the circuit. The minimum pickup rating should reach beyond the first-line recloser sectionalizing point, i.e., overlapping protection must be provided between the station recloser and the first-line recloser. If overlapping protection cannot be obtained when satisfying requirement (l), it will be necessary to relocate the first-line recloser to have it fall within the station recloser protective zone.

COORDINATION OF RECLOSERS AND FUSES

Figure 19 shows the time-current characteristic curves of the automatic circuit recloser. On these curves, the timecurrent characteristics of a fuse C is superimposed. It will be noted that fuse curve C is made up of two parts: the upper portion of the curve (low-current range) representing the total clearing time curve, and the lower portion (high-current range) representing the melting curve for the fuse.

The intersection points of the fuse curves with recloser curves A and B, define the limits between which coordination will be expected. It is necessary; however, that the characteristic curves of both recloser and fuse be shifted or modified to take into account alternate heating and cooling of the fusible element as the recloser goes through its sequence of operations.

Figure 20 shows what occurs when the current flowing through the fuse link is interrupted periodically. The oscillogram shows typical recloser operation. The first time the recloser opens and closes due to fault or overload, the action is instantaneous, requiring only two cycles. The second action is also two cycles, while the third action is delayed to 20 cycles, as is the fourth. Then the recloser locks itself open.

For example, if the fuse link is to be protected for two instantaneous openings, it is necessary to compare the heat input to the fuse during these two instantaneous recloser openings. The recloser-fuse coordination must be such that during instantaneous operation the fuse link is not damaged thermally.

Curve A’, Fig. 21, is the sum of two instantaneous openings (A) and is compared with the fuse damage curve which is 75 percent of the melting-time curve of the fuse.

This will establish the high-current limit of satisfactory coordination indicated by intersection point b’. To establish the low-current limit of successful coordination, the total heat input to the fuse represented by curve B’ (which is equal to the sum of two instantaneous (A) plus two time- delay (B) openings) is compared with the total clearing-time curve of the fuse. The point of intersection is indicated by a’.

For example, to establish how coordination is achieved between the limits of a’ and b’, refer to Fig. 21. It is assumed that the fuse beyond the recloser must be protected against blowing or being damaged during two instantaneous operations of the recloser in the event of a transient fault at X. If the maximum calculated short-circuit current at the fuse location does not exceed the magnitude of current indicated by b’, the fuse will be protected during transient faults. For any magnitude of

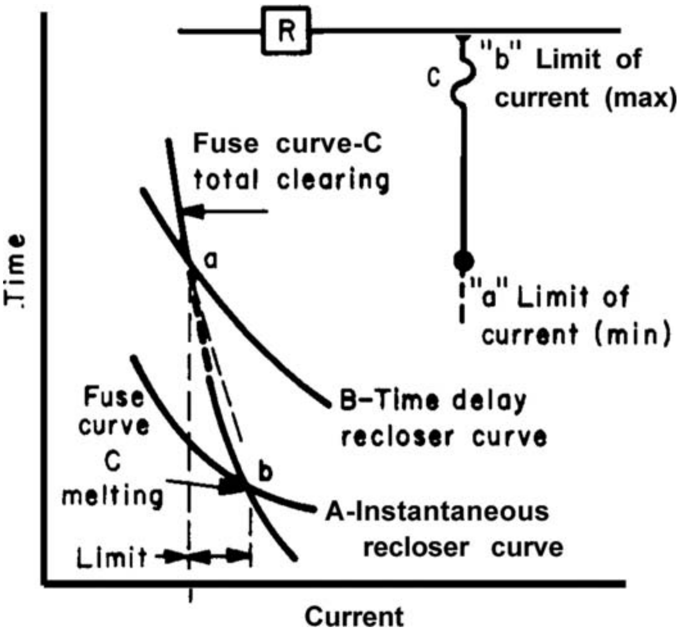

R
C
"b" Limit of current (max)
Fuse curve-C total clearing
a
"a" Limit of current (min)
Time
Fuse curve C melting
B-Time delay recloser curve
b
A-Instantaneous recloser curve
Limit
Current

Fig. 19. Time-current characteristic curves of recloser superimposed on fuse curve C

short-circuit current less than b’, but greater than a’ (see Fig. 21), the recloser will trip on its instantaneous characteristic once or twice to clear the fault before the fuse-melting characteristic is approached.

However, if the fault is permanent, the fuse should blow before the recloser locks out. If the minimum (line-to-ground) calculated short-circuit current available at the end of the branch is greater than the current indicated by a’, the fuse will blow (see Fig. 21) before the time-delay characteristic of the recloser is approached.

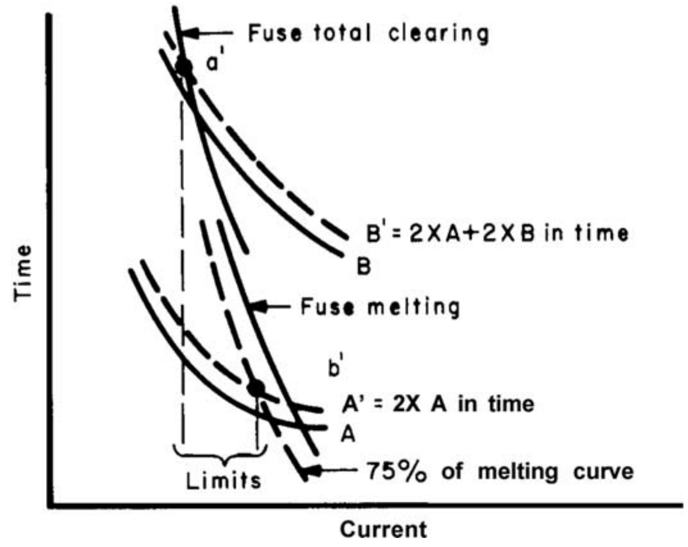


Fig. 21. Recloser-fuse coordination (fuse operated for heating and cooling)

STATIC OVERCURRENT RELAYS (SFC)

Since static over-current relays (SFC) are electronic analogs of conventional electromechanical relays, it is to be expected that the general principles of application covered earlier will still be pertinent. In general, this is true although there are several important differences which come about because the relay employs solid-state electronic operating principles.

In designing the SFC static overcurrent relay, it was recognized that the time-current characteristic could be built with any desired shape. Furthermore, the manner in which the relay operates ensures that the curve shape will remain essentially unchanged regardless of the actual time-dial setting. Thus, a critical decision in relay design was to choose a curve shape. It was judged to be important that the relay be designed so that it could easily be integrated into an existing system. This consideration essentially ruled out the use of totally new curve shapes and lead to a decision to duplicate the three basic time-current characteristics of IAC relays: inverse, very inverse, and extremely inverse. Because experience indicates that the lower time-dial settings on IAC relays tend to be used somewhat more frequently than the upper time-dial settings, the actual curves chosen for the new SFC relays were selected to match the lower time-dial curve from IAC relays.

However, it should be noted that there is no reason to insist that this match be exact. IAC curves were selected as design goals for convenience only; other curves could have been selected as well.

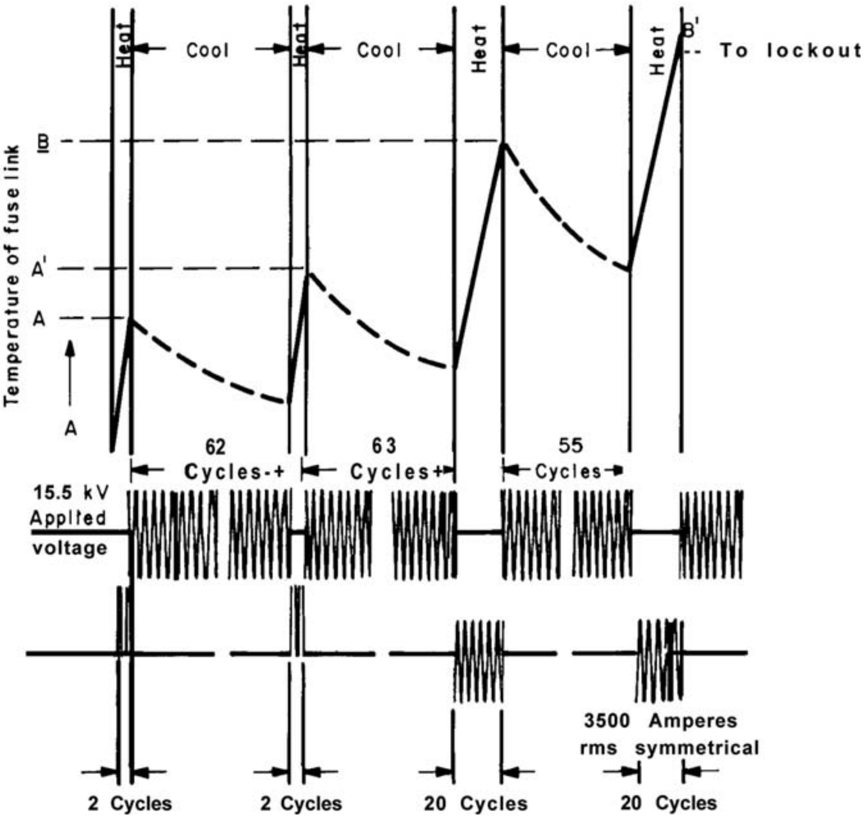


Fig. 20. Fuse link heating and cooling

Figure 22 illustrates the correlation between the curves of IAC (solid lines) and SFC (dashed lines) relays in the inverse, very inverse, and extremely inverse characteristics, respectively. A brief comparison of the curves reveals that the characteristics match very closely for lower time-dial settings, but at higher time dials there are noticeable differences both in time and shape. Therefore, it is very important to recognize that the SFC is functionally equivalent to an IAC of corresponding characteristic and that it may be used to advantage as a backup relay for an electromechanical relay or vice versa; however, it is equally important to recognize that a static SFC relay cannot be substituted for an electromechanical relay in an existing application without first determining an appropriate setting for the SFC in that application. Specifically, this means that equivalent settings for IAC and SFC relays will have identical pickup taps, but the time-dial calibration will be different.

Two specific areas where the electromechanical (IAC and IFC) and static (SFC) relay differ are overtravel and reset.

Overtravel in electromechanical relays is a function of the design of the relay, its pickup and time-dial settings, and the magnitude of fault current. It is not an easy number to determine precisely and tradition-

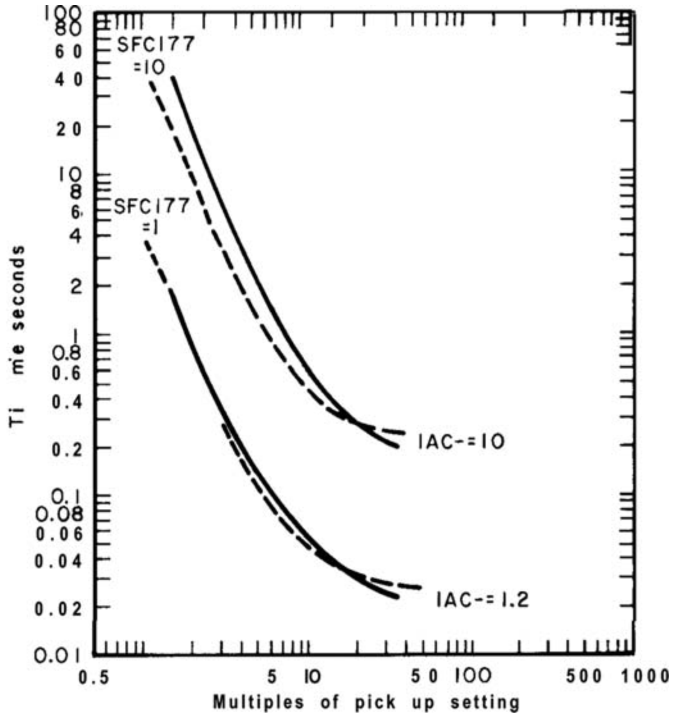


Fig. 22. Comparison of extremely inverse time-current characteristics of SFC 177 and IAC 77 relays

ally an estimate of 0.1 seconds has proved to be sufficiently long. Overtravel in the SFC static overcurrent relay is 0.01 seconds or less.

	IAC	IFC	SFC
Breaker time	0.0833	0.0833	0.0833
Overtravel	0.1000	0.1000	0.0100
Safety factor	0.1000	0.1000	0.1000
	0.2833	0.2833	0.1933

Based upon these numbers, the following minimum coordination margins can be determined:

For practical purposes, these numbers can be given as 0.3 seconds for IAC and IFC electromechanical relays and 0.2 seconds for SFC static relays.

Reset time is the time required for the relay to return to its fully reset position after the recloser has interrupted the short circuit. For conventional electromechanical relays, reset time is very long. The IAC 77 takes a full minute to return to the reset position from the contact-closed position when set on the number 10 time dial.

However, the static SFC relay resets in 0.1 seconds or less regardless of the characteristic or time dial used, which is faster than the reclosing time of any distribution recloser or breaker available today. This difference is best illustrated by an example,

Consider the system of Fig. 23. The pole-type recloser is set for one fast and three time-delay trips and its reclose time is two seconds. In coordinating relays and reclosers, a margin of 0.15 to 0.2 seconds is normally considered the minimum safe tolerance. In this instance, in anticipation of possible problems with reset, a longer margin (0.3 seconds) was selected as a point of departure.

The feeder breaker is equipped with an instantaneous overcurrent relay set at 5362 amperes (primary) for an equivalent coverage of approximately 1.5 miles of 13.8-kV circuit. The instantaneous unit is blocked after the first trip and the reclosing relay on the feeder breaker is adjusted for a CO+5+CO+5+CO+5+CO operating cycles. The backup relay at the substation is shown as a partial differential (summation overcurrent) connection, although this is not significant to the example.

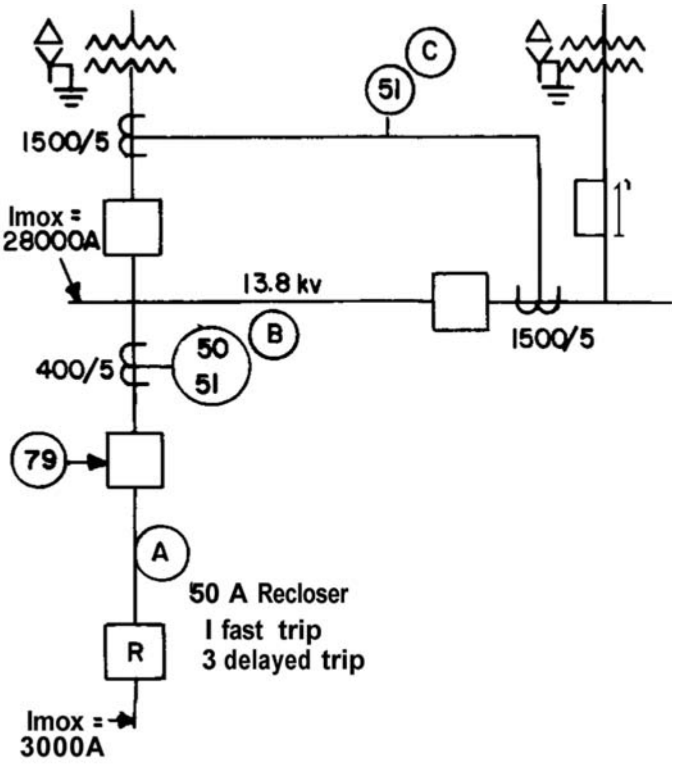


Fig. 23. Sample system for recloser-relay coordination illustration

Figure 24 shows the time-current curves for this system using electromechanical IAC 77 relays. The trial setting for the feeder relay is shown as the dashed curve B and a 320-ampere pickup and number 7 time dial. With this time dial, the reset time of the IAC 77 is about 42 seconds. It is significant to observe that even though the curves show an apparent margin of 0.3 seconds, the true margin between the IAC 77 and the recloser is only 0.103 seconds as determined in Table 1. Thus the number 8 time dial is required as noted by the solid curve B in Fig. 24.

Similarly, the apparent margin for the backup relay is not sufficient because of reclosing by the feeder breaker, and a higher time dial must be used to assure a minimum of 0.3- second margin between relays.

In Fig. 25 the system curves are again drawn, but this time for static SFC 177 relays on the feeder breaker and as the backup relay, the reset time of the SFC (0.1 seconds) is faster than the reclosing delay of either the automatic recloser or the reclosing feeder breaker. Therefore, no consideration at all need be given to “notching” and the relay settings can be determined by the time-current curves alone. Also, because overtravel is negligible, the margin between the backup and feeder relays can be reduced to 0.2 seconds at the maximum fault level. The result is that the backup clearing time is 0.15 seconds faster at the maximum fault level when static SFC overcurrent relays are used; at a fault limited to 1.5 times the pickup of the backup relay, static relays are a full 10 seconds faster in operation.

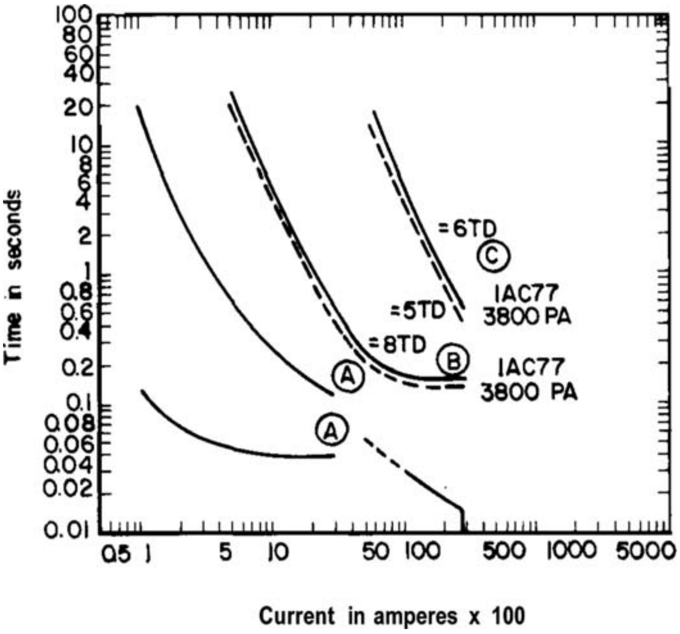


Fig. 24. Pole-type recloser vs IAC 77 relay coordination example

GROUND FAULT DETECTION

A complex problem, for which there is no ready solution, is high impedance ground-fault detection and protection.

Table 1

Recloser Operation	IAC 77 Feeder-relav Oneration
Trip No. 1 (Instantaneous) = 0.04 sec	$\frac{0.04}{0.44}$ 100 = 9.091% Travel
Reclose Time = 2 sec	$\frac{2}{42}$ 100 = 4.762% Reset
Trip No. 2 (Time) = 0.12 sec	$\frac{0.12}{0.44}$ 100 = 27.273% Travel
Reclose Time = 2 sec	$\frac{2}{42}$ 100 = 4.762% Reset
Trip No. 3 (Time) = 0.12 sec	$\frac{0.12}{0.44}$ 100 = 27.273% Travel
Reclose Time = 2 sec	$\frac{2}{42}$ 100 = 4.762% Reset
Trip No. 4 (Time) = 0.12 sec	$\frac{0.12}{0.44}$ 100 = 27.273% Travel
Lockout	9.091 - 4,762 + 27.273 4.762 ±27.273 - 4.762 t 27.273= 76.624% Travel

True Margin = Remaining Travel = (1 0.76624) (0.44 set) = 0.103 sec

Calculation of IAC 77 Relay Margin Against Pole-type Recloser

This is also a very serious problem in that personnel safety is involved, particularly so when a live conductor drops to the ground and there is insufficient fault current available to operate protective devices. Sensitivity is determined by the permissible unbalance in a four-wire grounded system and/or the number of breaker operation interruptions that can be tolerated. Where the majority of all faults that occur on a four-wire distribution system initiate as line-to-ground faults and where many are of the self-clearing type, it must be evaluated whether or not very sensitive ground tripping can be justified with the acceptance of the many unnecessary interruptions that can be expected.

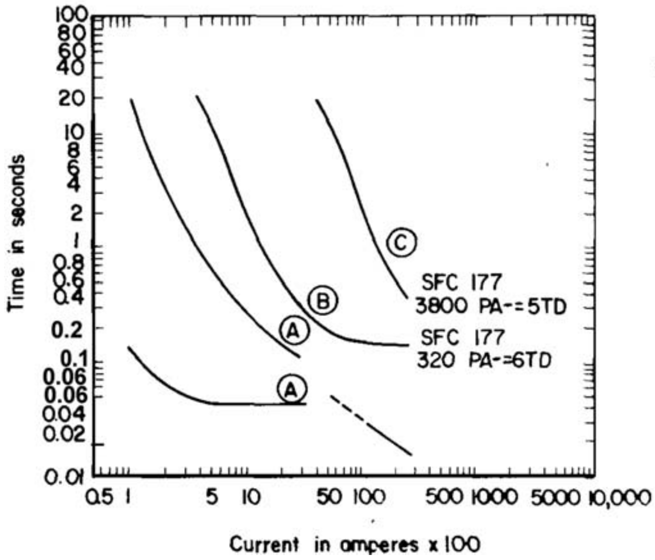


Fig. 25. Pole-type recloser vs SFC 177 relay coordination example

UNBALANCE

The problem of setting ground-relay sensitivity to include all faults, yet not trip for heavy-load currents or load inrush, is not as difficult as it is for phase relays. If the three-phase load is balanced, normal ground current is near zero. Therefore, the ground relay should not be affected by load current and can have a sensitive setting.

Unfortunately, it is difficult to keep the loads on the distribution system balanced to the point where ground relays can be set to pick up on as little as 25 percent of load current. Most ground relays are set to pick up at about 50 percent of load current.

FAULTS

The two basic factors affecting low-magnitude ground current are line impedance and fault impedance.

The line impedance can be readily calculated on the basis of a “bolted” fault. However, it is often recognized that in many cases the magnitude of measurable shortcircuit current is less than indicated by calculations. This is understandable in view of the many variables not accounted for in calculations. For example, conductor-splice resistance, reduced generating capacity, low system voltage at time of fault, voltage reduction due to the fault at the time of interruption, and error in calculations due to incorrect circuit footage, transpositions, and configurations.

In addition, a big factor known to exist, but not possible to calculate or obtain from industry records, is fault impedance.

This factor in itself can vary due to the type of fault, ground resistivity, contact pressure and weather and tree conditions. This factor has a decided effect in reducing the shortcircuit current magnitude.

In 7.2/12.47 kV short-circuit calculations, a factor of 30, 35 or 40 ohms is often used as the fault resistance in determining minimum values of line-to-ground current available. However, these values are purely imaginative values without ample substantiation.

With the general acceptance by utility operators of the use of the coordinated recloser-fuse method of distribution line sectionalizing, the problem of high-impedance groundfault protection is greatly simplified in the fringe areas.

However, the problem is further complicated in protection of the main circuit close to the substations. Where ground relays are generally accepted as a means of ground fault detection and protection, the minimum setting is usually established by the maximum unbalance that could exist with the heaviest loaded single-phase branch interrupted. In all probability, this setting will be less than the minimum pickup value of the nearest automatic circuit recloser.

Hence, if reclosers are to be used out on the distribution feeder, ground relays must be adjusted to have a minimum pickup higher than 200 percent of the largest rated recloser or be disconnected entirely. When the ground relay is adjusted as high as required, it loses its effectiveness as ground protection.

It is possible to add time delay to the ground relays so that they may be set lower than the reclosers and still achieve coordination. This feature could be utilized to achieve back-up protection for some of the ground faults that are in the recloser protective zone and disconnect the feeder if the recloser fails to function.

The combination of low-rated reclosers and fuses properly coordinated and located on the branch and fringe ends of the circuit will provide the possibility of interrupting low values of ground current, i.e., where reclosers can be applied with thermal ratings approximately 30 percent greater than full-load current at the point of installation and do have adequate interrupting capacity. Thus the possibility of operating on low-magnitude ground current is more assured than if operation is dependent upon the groundcurrent relays at the substation.

In a few cases, detection of a fallen conductor has been considered so important that loads have been connected line-to-line, so there could be no neutral current due to unbalance. The neutral has been grounded through high resistance to limit the ground current thus minimizing the effect of fault resistance on fault-current magnitude. Very sensitive ground relays have been installed with this system to assure clearing of conductors that have fallen.

CONDUCTOR BURNDOWN

Conductor burndown is a function of (1) conductor size (2) whether the wire is bare or covered (3) the magnitude of the fault current (4) climatic conditions such as wind and (5) the duration of the fault current.

If burndown is less of a problem today than in years past, it must be attributed to the trend of using heavier conductors and a lesser use of covered conductors. However, extensive outages and hazards to life and property still occur as the result of primary lines being burned down by flashover, tree branches falling on lines, etc. Insulated conductors, which are used less and less, anchor the arc at one point and thus are the most susceptible to being burned down. With bare conductors, except on multi-grounded neutral circuits, the motoring action of the current flux of an arc always tends to propel the arc along the line away from the power source until the arc elongates sufficiently to automatically extinguish itself. However, if the arc encounters some insulated object, the arc will stop traveling and may cause line burndown.

With bare conductors, on multi-grounded neutral circuits, the motorizing effect occurs only on the phase wire since current may flow both ways in the neutral. When the 25 percent of the burndown and the protective equipment should be installed to limit the currents and times to less than those given.

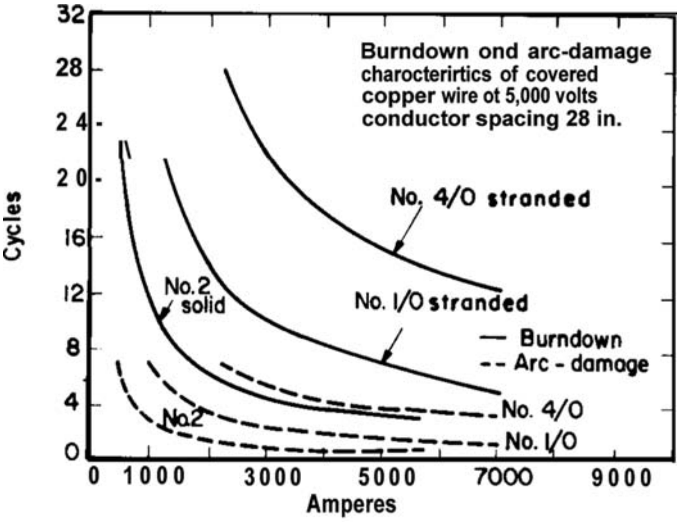


Fig. 26. Burndown characteristics of several weatherproof conductors

With tree branches falling on bare conductors, the arc may travel away and clear itself; however, the arc will generally re-establish itself at the original point and continue this procedure until the line burns down or the branch fails off the line. Limbs of soft spongy wood are more likely to burn clear than hard wood. However, one-half inch diameter branches of any wood, which cause a flashover, are apt to burn the lines down unless the fault is cleared quickly enough.

Figure 26 shows the burndown characteristics of several weatherproof conductors. Arc damage curves are given as arc is extended by traveling along the phase wire, it is extinguished but may be re-established across the original path. Generally the neutral wire is burned down.

Figure 27 shows the coordination between the arc damage and burndown characteristics for a No. l/O conductor and the protective devices which must operate to prevent serious conductor damage. This curve shows that with the present breaker operating times, the feeder breaker would afford little protection. It should be realized that the breaker time used was assumed to be eight cycles regardless of the fault current. In an actual case, the breaker time would probably be less than one half this value at its nameplate interrupting rating.

The use of automatic circuit reclosers and fuses will greatly improve the protection of conductors against burndown as shown in Fig. 27. Proper utilization of reclosers and fuses should provide protection for all conductors within the current range shown.

As systems increase in size, many engineers are worried

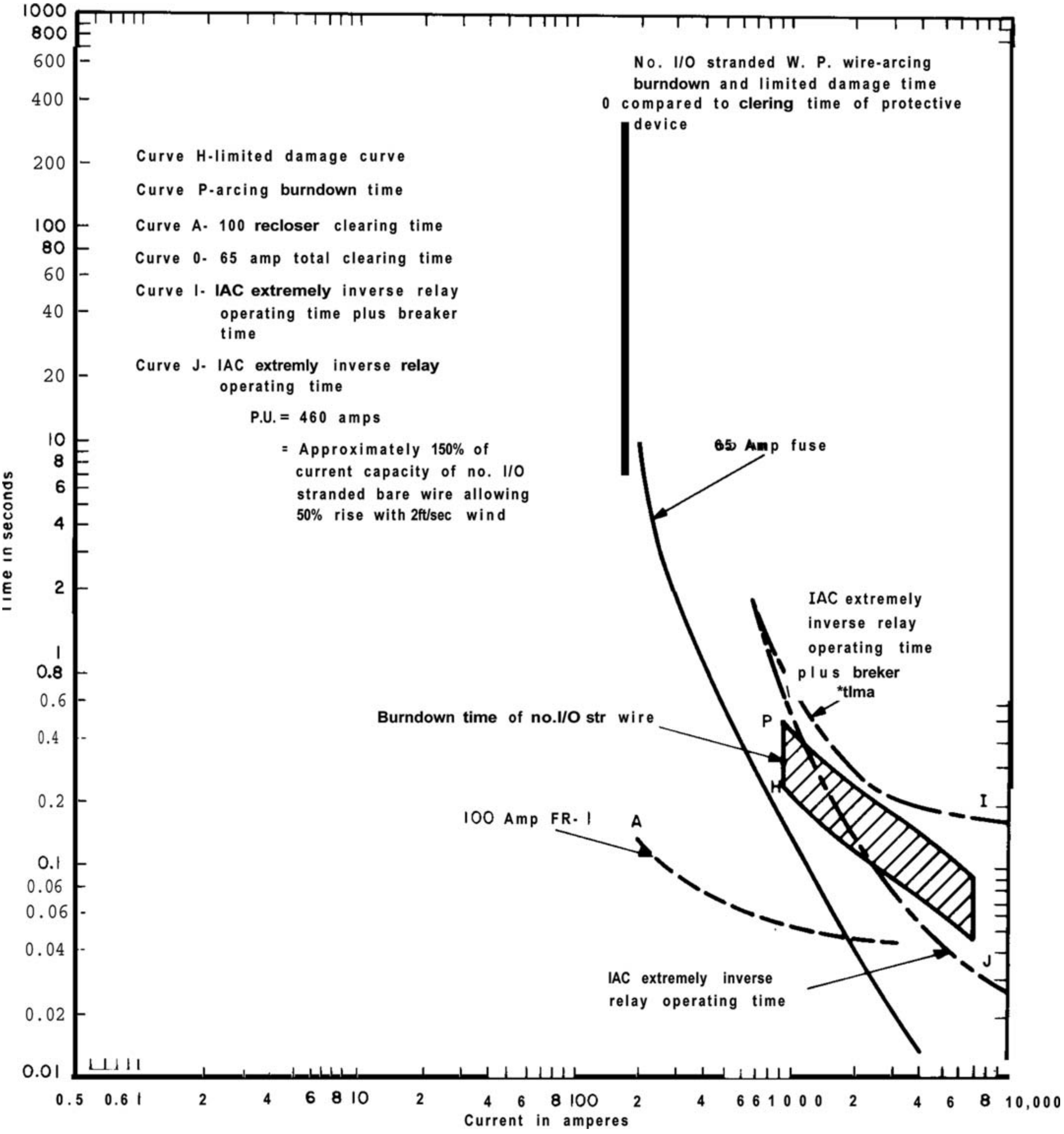


Fig. 27. Curves illustrating coordination between the arc damage and burndown characteristics for a No. I/O conductor land the protective devices which must operate to prevent serious conductor damage

about burndown becoming more of a problem since the available short-circuit current will increase. This problem may be delayed by the sectionalizing of buses and the addition of current-limiting reactors. It is quite possible that proper sectionalizing may delay the problem indefinitely for some systems.

The proper use of reclosers and fuses, along with higher speed breakers, should prevent most conductor burndown problems.

APPENDIX A

FUNCTIONS AND DEFINITIONS

The devices in the switching equipments are referred to by numbers, with appropriate suffix letters (when necessary), according to the functions they perform. These numbers are based on a system which has been adopted as standard for automatic switchgear by the America Standards Association.

Device No.	Function and Definition
11	CONTROL POWER TRANSFORMER is a transformer which serves as the source of A-C control power for operating A-C devices.
24	BUS-TIE CIRCUIT BREAKER serves to connect buses or bus sections together.
27	A-C UNDERVOLTAGE RELAY is one which functions on a given value of singlephase A-C undervoltage.
43	TRANSFER DEVICE is a manually operated device which transfers the control circuit to modify the plan of operation of the switching equipment or of some of the devices.
50	SHORT-CIRCUIT SELECTIVE RELAY is one which functions instantaneously on an excessive value of current or on an excessive rate of current rise, indicating a fault in the apparatus or circuit being protected.
51	A-C OVERCURRENT RELAY is one which functions when the current in an a-c circuit exceeds a given value.
52	A-C CIRCUIT BREAKER is one whose principal function is usually to interrupt short-circuit or fault currents.
64	GROUND PROTECTIVE RELAY is one which functions on failure of the insulation of a machine, transformer or other apparatus to ground. This function is, however, not applied to devices 51N and 67N connected in the residual or secondary neutral circuit of current transformers.
67	A-C POWER DIRECTIONAL OR A-C POWER DIRECTIONAL OVERCURRENT RELAY is one which functions on a desired value of power flow in a given direction or on a desired value of overcurrent with A-C power flow in a given direction.
78	PHASE-ANGLE MEASURING RELAY is one which functions at a pre-determined phase angle between voltage and current.
87	DIFFERENTIAL CURRENT RELAY is a fault-detecting relay which functions on a differential current of a given percentage or amount.

The above numbers are used to designate device functions on all types of manual and automatic switchgear, with exceptions as follows:

FEEDERS - A similar series of numbers starting with 101 instead of 1 is used for the functions which apply to automatic reclosing feeders.

HAND RESET -The term "Hand Reset" shall be added wherever it applies.

LETTER SUFFIXES -These are used with device function numbers for various purposes as follows:

1. CS - Control Switch
X - Auxiliary Relay
Y - Auxiliary Relay
YY - Auxiliary Relay
Z - Auxiliary Relay

2. To denote the location of the main device in the circuit or the type of circuit in which the device is used or with which it is associated, or otherwise identify its application in the circuit or equipment, the following are used:
N - Neutral
SI - Seal-in

3. To denote parts of the main device (except auxiliary contacts as covered under (4) below), the following are used:
H - High Set Unit of Relay
L - Low Set Unit of Relay
OC - Operating Coil
RC - Restraining Coil
TC - Trip Coil

4. To denote parts of the main device such as auxiliary contacts (except limit-switch contacts covered under (3) above) which move as part of the main device and are not actuated by external means. These auxiliary switches are designated as follows:
"a" - closed when main device is in energized or operated position
"b" - closed when main device is in de-energized or non-operated position

5. To indicate special features, characteristics, the conditions when the contacts operate, or are made operative or placed in the circuit, the following are used:
A - Automatic
ER - Electrically Reset
HR - Hand Reset
M - Manual
TDC - Time-delay Closing
TDDO - Time-delay Dropping Out
TDO - Time-delay Opening

To prevent any possible conflict, one letter or combination of letters has only one meaning on individual equipment. Any other words beginning with the same letter are written out in full each time, or some other distinctive abbreviation is used.

HOW TO SET AN IAC RELAY

Time and current settings of IAC relays are made by selecting the proper current tap and adjusting the time dial to the number which corresponds to the characteristic required.

The following example illustrates the procedure.

Assume an IAC inverse-time relay in a circuit where the circuit breaker should trip on a sustained current of approximately 450 amperes, and that the breaker should trip in 1.9 seconds on a short-circuit current of 3750 amperes.

Assume further that current transformers of 60:1 ratio are used.

Find the current tap setting by dividing the minimum primary tripping current by the current transformer ratio:

$$\frac{450}{60} = 7.5$$

Since there is no 7.5-ampere tap, use the 8-ampere tap.

To find the time setting which will give 1.9-second time delay at 3750 amperes, divide 3750 by the transformer ratio. This gives 62.5-amperes secondary current, which is 7.8 times the 8-ampere tap setting.

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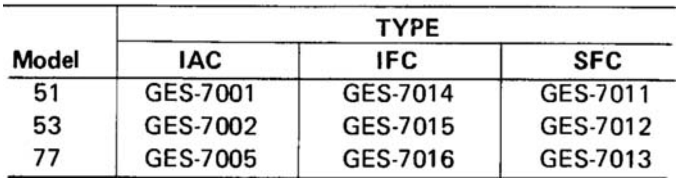

Model	TYPE		
	IAC	IFC	SFC
51	GES-7001	GES-7014	GES-7011
53	GES-7002	GES-7015	GES-7012
77	GES-7005	GES-7016	GES-7013

TRANSIENT RECOVERY VOLTAGE (TRV) FOR HIGH-VOLTAGE CIRCUIT BREAKERS

R.W. Alexander, PPL, Senior Member IEEE, D. Dufournet, Alstom T&D, Senior Member IEEE

1 GENERAL

The recovery voltage is the voltage which appears across the terminals of a pole of a circuit breaker. This voltage may be considered in two successive time intervals: one during which a transient voltage exists, followed by a second one during which a power frequency voltage alone exists.

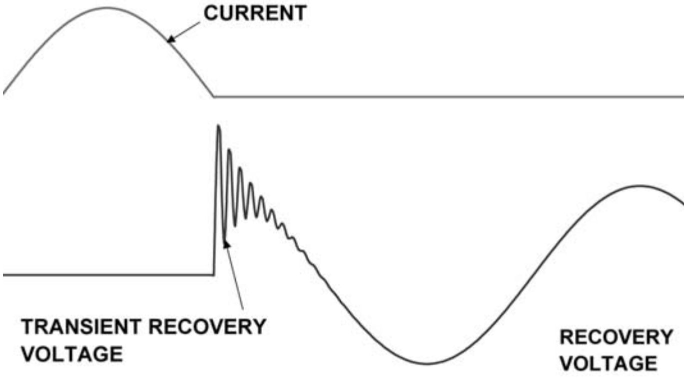

Figure 1 Current, TRV and Recovery Voltage

During the interruption process, the arc rapidly loses conductivity as the instantaneous current approaches zero. Within a few microseconds after current zero, current stops flowing in the circuit. The power system response to the current interruptions is what generates TRV. The difference in the power system response voltage from the source side to the load side of the circuit breaker is the TRV. The breaking operation is successful if the circuit breaker is able to withstand the TRV and the power frequency recovery voltage. TRV is then related to the power system response to an interruption of current in a circuit very close to a power frequency current zero. The nature of the TRV is dependent on the circuit being interrupted, whether primarily resistive, capacitive or inductive, (or some combination). Additionally, distributed and lumped circuit elements will produce different TRV waveshapes.

In principle, the response of the load side and source side of the circuit breaker can be analyzed separately, and the results subtracted point by point on a time line. The driving voltage will be the instantaneous power frequency voltage across the circuit elements at the instant of current interruption. If there is no damping, the highest peak circuit response would be 2 times the driving voltage. The proportion of the system voltage across each piece of the switched circuit will be determined by the impedance of each piece at the power frequency.

When interrupting a fault at the circuit breaker terminal in an inductive circuit, the supply voltage at current zero is maximum. The circuit breaker interrupts at current zero, at a time when the power input is minimum, and the voltage on the supply side terminal reaches the supply voltage in a transient process called the transient recovery voltage. This is illustrated in Figure 2.

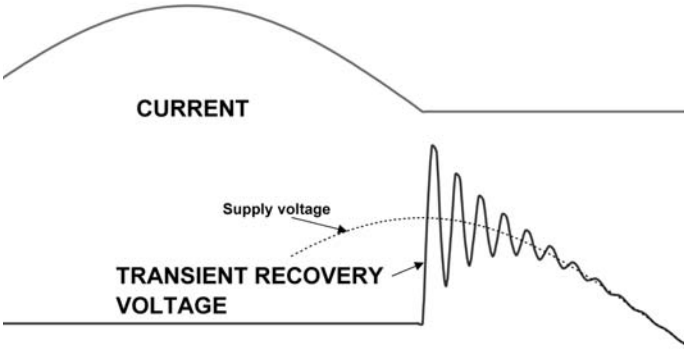

Figure 2 Current and TRV waveforms during interruption of inductive current

The TRV frequency is $\frac{1}{2\pi\sqrt{LC}}$, with L = short circuit inductance, C = supply capacitance.

When a pure resistive circuit is interrupted, the supply voltage is zero at the time of interruption, therefore the recovery voltage has no transient component (see Figure 3).

A capacitively dominated circuit will have crest voltage across the capacitive elements at the instant of current interruption, this will give a DC offset on the TRV. In the simplest case, the TRV will be a 1-cosine of the power frequency, oscilating between 0 and 2 p.u.

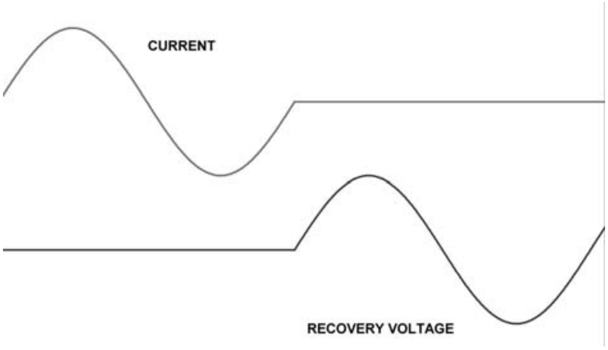

Figure 3 Current and TRV waveforms during interruption of resistive current

In an inductively dominated circuit, the supply voltage at the instant of current interruption will be close to peak (see figure 2). A pure inductive circuit would then have a TRV which is a 1 p.u. step function, followed by a cosine wave of power frequency. This would have an infinitely fast rate of rise and could only be interrupted by an ideal circuit breaker. In real life, there is always some shunt capacitance of the inductor, which in the most onerous case, gives rise to an oscillatory TRV. The frequency of the oscilation will be determined by the L and C involved. The TRV peak will at worst be 2.0 times the driving voltage. In cases where there is sufficient damping, the inductive circuit will produce a $1 - e^{-\alpha t}$ wave shape.

Figure 4 illustrates three types of recovery voltages in resistive, inductive and capacitive circuit.

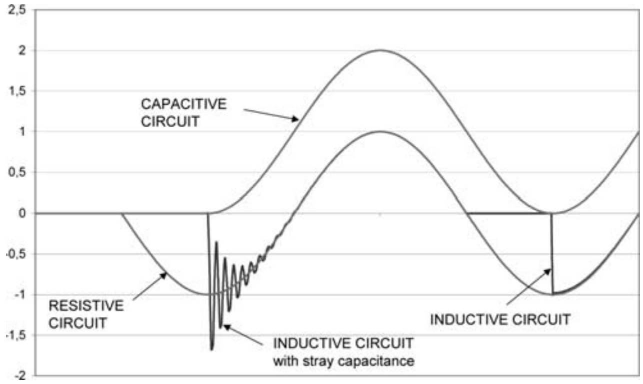

Figure 4 TRV and recovery voltage in resistive, inductive or capacitive circuits

Circuits for mainly active load current switching can be simulated by a combination of resistive and inductive elements. The recovery voltage is a combination of that shown in figure 4 for resistive and inductive circuits. It has initially a high frequency transient, due to the voltage drop in the transformer reactance, followed by a power frequency voltage, the amplitude of which is function of the load power factor.

In a similar way, interruption in a L-C series circuit produces initially a high frequency TRV of small amplitude (the voltage prior to interruption tends toward the supply voltage value) called the voltage jump, followed by the 1 - cos waveshape shown on figure 4 for a capacitive circuit.

An open circuited line will act much like a capacitor (representing the distributed capacitance). If the line is very long, the Ferranti effect (voltage rise along an unloaded line due to the line's capacitive charging current being drawn through its own inductance) can produce a higher voltage at the far end. After circuit interruption, the voltage profile along the line will "travel" and a peak TRV higher than 2.0 p.u. can result across the circuit breaker interrupter.

A short-circuited line will have a "ramp" voltage profile along the line. Upon interruption, this ramp will "travel". Depending on the electrical circuit discontinuities, there will be reflections. Still a 2.0 p.u. voltage would be the maximum expected peak (remember that lines can comprise part (or all) of the source or load impedance or both).

There is a TRV for any interruption not just for fault interruptions. Although fault interruptions are often considered to produce the most onerous TRVs, there are many exceptions such as shunt reactor switching (see section 7.3).

TRVs can be oscillatory, triangular, or exponential and can occur as a combination of these forms. A DC offset may also be present as it is the case for lines with series capacitors.

As shown in annex A.1, a network can be reduced to the simple parallel RLC circuit of figure 5 for TRV calculations. This representation is reasonably valid for short-time frames until voltage reflections return from discontinuities in the network.

The TRV in the parallel RLC circuit is oscillatory (underdamped) if $R > \frac{1}{2}\sqrt{L/C}$

The TRV in the parallel RLC circuit is exponential (overdamped) if $R \leq \frac{1}{2}\sqrt{L/C}$

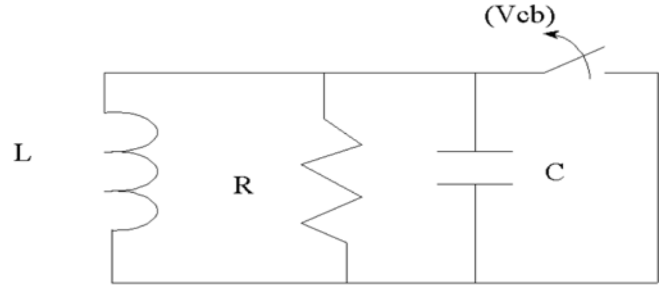

Figure 5 – Equivalent RLC circuit

Figure 6 shows the TRV shape as function of damping in an RLC circuit. From this figure, it can be seen that by lowering the resistance in the equivalent circuit, for example when adding a resistance of low ohmic value in parallel to the interrupting chamber(s), it is possible to effectively reduce the rate-of-rise of TRV (the TRV peak voltage is reduced as well). This method has been widely used for many years to assist current interruption by air-blast circuit breakers.

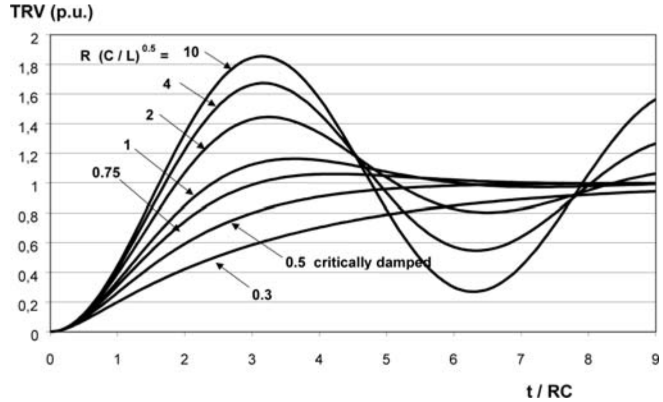

Figure 6 – TRV shape in RLC parallel circuit

When longer time frames are considered, typically several hundreds of micro-seconds, reflections on lines have to be taken into account. Lines or cables must then be treated as components with distributed elements on which voltage waves travel after current interruption. These traveling waves are reflected and refracted when reaching an open circuit or a discontinuity. The principles are explained in annex A.3, and a practical application for the determination of short-line fault TRV is covered in annex A.5.2.

The most severe oscillatory or exponential recovery voltages tend to occur across the first pole to clear of a circuit breaker interrupting a three-phase symmetrical fault at its terminal when the system voltage is maximum. A 3-phase fault with no ground return (either an ungrounded fault, or an ungrounded system, or both) will produce the highest recovery voltages on the first pole to clear.

TRV peak is function of the grounding arrangement of the system, it is lower in effectively grounded systems than in ungrounded systems (see section 5 for additional information on the TRV and power frequency recovery voltage applied on each pole while interrupting a three-phase terminal fault). While three-phase ungrounded faults produce the higher TRV peaks, the probability of their occurrence is very low, therefore the TRV ratings are based on three-phase grounded faults (see section 6.1).

By definition, all TRV values defined in the standards are inherent, i.e. the values that would be obtained during interruption by an ideal circuit breaker without arc voltage (its resistance changes from zero to an infinite value at current zero).

2 EXPONENTIAL (OVERDAMPED) TRV

A typical exponential TRV is shown in Figure 7. It is obtained typically on the source side of a circuit breaker during interruption of a fault at the circuit breaker terminals. This exponential part of TRV occurs when the equivalent surge impedance of the n connected lines in parallel

$$Z_{eq} = \alpha \frac{Z_1}{n}$$

where Z_1 is the positive sequence surge impedance of a line and α is a factor equal to 1.5 in the case of three-phase ungrounded faults and a function of Z_0/Z_1 in other cases) is lower than $0.5\sqrt{L_{eq}/C_{eq}}$ (L_{eq} = equivalent source inductance, C_{eq}= equivalent source capacitance). Detailed explanations are given in A.2 and A.3.

The exponential part of TRV, defined by equation $V_{cb}=V_0(1 - e^{-t/\tau})$, appears also as traveling waves on each of the transmission lines. Reflected wave(s) returning from open line(s) contribute also to the TRV as shown on figures 7 and 9.

The initial rate-of-rise of recovery voltage is given by

$$RRRV = \frac{\alpha Z_1}{n} \times \frac{di}{dt}$$

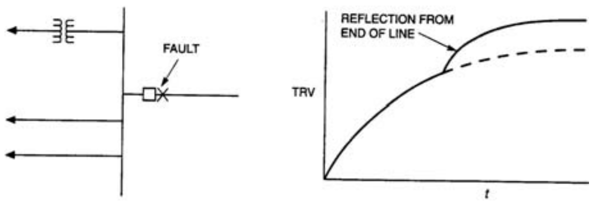

Figure 7 Exponential TRV characteristic

As higher short-circuit currents are associated with an increasing number of connected lines and the TRV is less influenced by the transformer natural frequency, the RRRV tends to decrease when the short-circuit current increases.

As an example, Figure 8 shows the one-line diagram of a 550 kV substation. Figure 9 illustrates the TRV seen by circuit breaker A when clearing the three-phase fault shown in figure 8 (circuit breaker B is open). This waveform is overdamped and exhibits an exponential waveshape. In figure 9, a reflection occurs from the end of the shortest line after approximately 535µs, causing a slight increase in the TRV crest. Figure 9 also shows the TRV capability curve of a circuit breaker indicating that the breaker TRV capability exceeds system requirements.

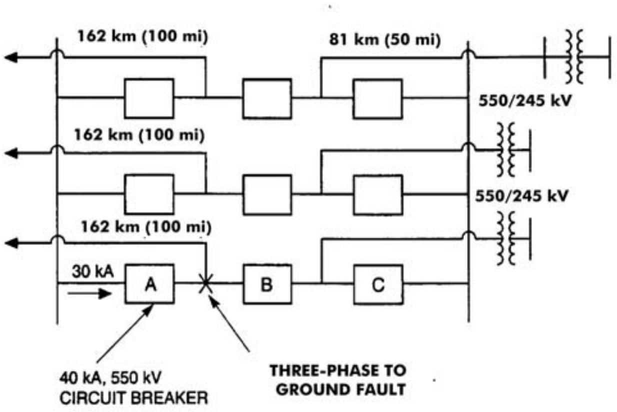

Figure 8- System configuration

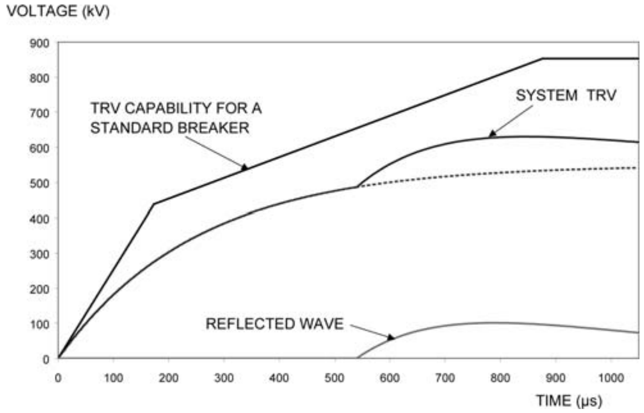

Figure 9 – Comparison of TRV capability for 550 kV circuit breaker and system TRV

3 OSCILLATORY (UNDERDAMPED) TRV

The oscillatory TRV shown in Figure 10 occurs generally when a fault is limited by a transformer or a series reactor and no transmission line or cable surge impedance is present to provide damping.

Even when overhead lines are present, it is possible for the recovery voltage to be oscillatory. To be oscillatory, the surge impedance of a source side line has to be such that the equivalent surge impedance Z_{eq} is equal or higher than $0.5\sqrt{L_{eq}/C_{eq}}$ (L_{eq} = equivalent source inductance, C_{eq} = equivalent source capacitance), it follows that the number of lines connected is necessarily small and that the short-circuit current is

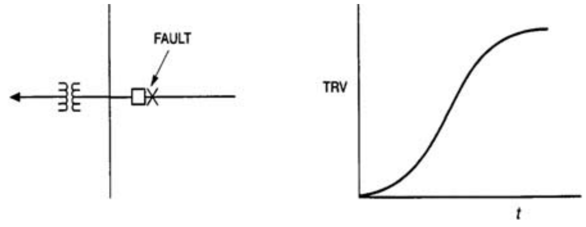

Figure 10 – Transformer limited fault and oscillatory TRV characteristic

generally low, up to 30% of rated short-circuit current. An exception could be a transformer circuit breaker. in this case, the maximum fault duty could have an oscillatory TRV. Detailed explanations are given in A.3.

The characteristics (peak value and rate-of-rise) of oscillatory TRVs are often covered by the rated values defined in ANSI/IEEE Std C37.06 for terminal faults at 10% or 30% of rated short-circuit current.

Severe TRV conditions occur in some cases, for instance when short-circuit occurs immediately after a transformer without any appreciable additional capacitance between the transformer and the circuit breaker. In such cases, both the peak voltage and rate-of-rise of transient recovery voltage may exceed the values specified in ANSI/IEEE Std C37.06 (see Figure 12). Such cases are covered by the TRV ratings fast time-to-peak values for definite purpose circuit breakers given in ANSI C37.06.1-2000.

As an example, Figure 11 shows the case of a 40 kA, 145 kV circuit breaker that has to clear a three-phase fault at 10% of its rating. The resultant TRV is shown in Figure 12. This TRV is determined by the inductance and capacitance of the transformer and by the capacitance between the transformer and the circuit breaker. In this particular case, the circuit breaker does not have the capability to withstand the imposed system TRV, unless the system is modified.

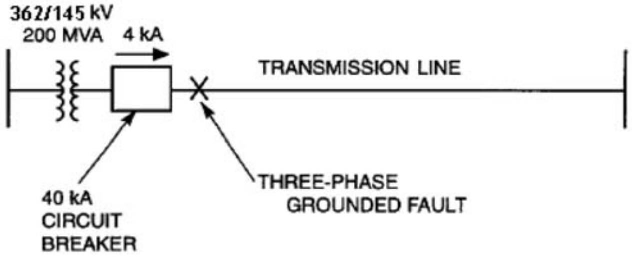

Figure 11 - Fault location

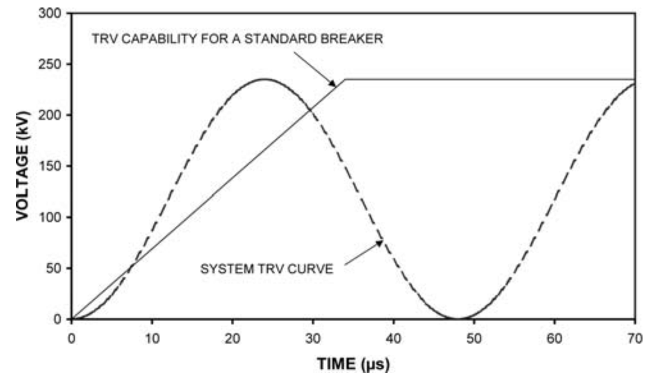

Figure 12 - Comparison of TRV capability for 145 kV circuit breaker (at 10% of its rated interrupting current capability) and system TRV

The system TRV curve can be modified by a capacitance and then be within the standard capability envelope (see section 7).

4 SHORT-LINE FAULT – TRIANGULAR WAVESHAPE

Triangular-shaped TRVs are associated with short-line faults (SLF). After current interruption, the line side voltage exhibits the characteristic triangular waveshape shown in Figure 13 (see annex A.5.2 for explanations on the triangular waveshape).

The rate-of-rise of the saw-tooth shaped TRV is a function of the line surge impedance. The rate-of rise is generally higher than that experienced with exponential or oscillatory TRVs, however the TRV peak is generally lower.

Because overhead lines have distributed electrical parameters (series resistance, shunt conductance, shunt capacitance and series inductance), the line side voltage oscillates in the form of a traveling wave with positive and negative reflections at the open breaker and at the fault, respectively. The line side component of the recovery voltage has a sawtooth shape and a high rate of rise. Generally, the source recovery voltage rises much more slowly and only the line side triangular recovery voltage is important during the early portion of the TRV (see Figure 14). The closer the fault is to the circuit breaker, the higher the initial rate of rise of the line side recovery voltage due to the higher fault current, while the crest magnitude of this line side triangular wave decreases due to the shorter time for the reflected wave to return.

The amplitude and rate-of-rise of TRVs for these short-line faults are determined on a single-phase basis during their early time periods (typically less than 20 µs) when the source side voltage changes only slightly. Later in time, the TRV is less severe than for three-phase terminal faults.

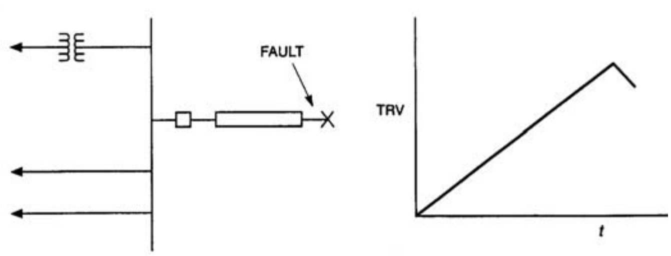

Figure 13 - Short-line fault TRV characteristic

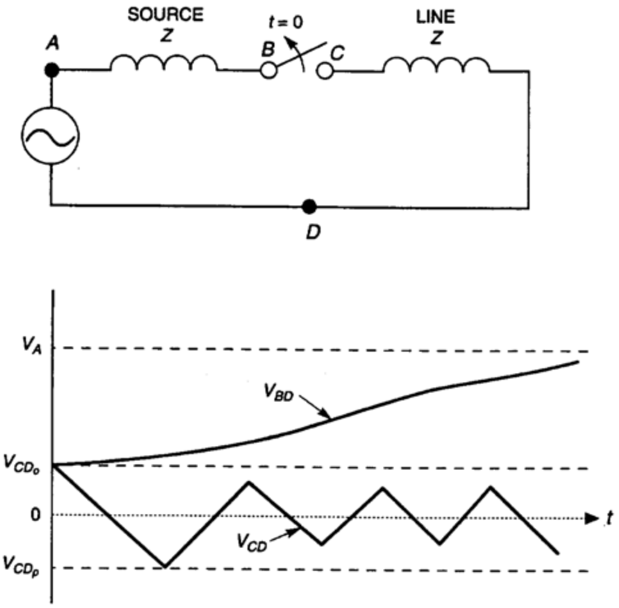

Figure 14 - TRV waveshape for short-line fault
VBD = source side voltage, VCD = line side voltage

The fault current for a line side fault is somewhat reduced from that obtained for a bus fault due to the additional reactance of the line. Let IT be the fault current through the circuit breaker for a single-phase fault at the breaker terminal, and IL be the reduced current for a line fault.

Figure 15 illustrates the single-phase circuit where the short-circuit current is limited by the source reactance (X_S) in series with the line reactance ($X_L\lambda$):

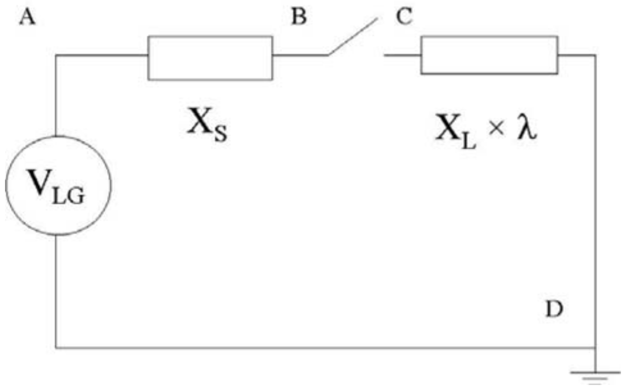

Figure 15 Single-phase circuit with short-line fault

$$I_L = \frac{V_{LG}}{X_L\lambda + X_S}$$

The source side reactance is given by

$$X_S = \frac{V_{LG}}{I_T}$$

The fault current is then

$$I_L = \frac{V_{LG}}{X_L\lambda + V_{LG}/I_T}$$

where

X_L is $(2\,L_{1W} + L_{0W})\,\omega/3$

X_L is the reactance of the line to the fault point per unit length

L_{1W} is the positive sequence power frequency line inductance per unit length

L_{0W} is the zero sequence power frequency line inductance per unit length

V_{LG} is the system line-ground voltage

λ is the distance from the opening circuit-breaker to the fault

In general, it is not necessary to calculate the SLF TRV as long as the terminal fault TRVs are within rating and transmission line parameters are within the values specified in ANSI/IEEE Std C37.04. The transmission line parameters are given in terms of the effective surge impedance, Z_{eff}, of the faulted line and the peak factor, d, defined as:

$$d = 2\omega\frac{Z_{eff}}{X_L v}$$

where:

$Z_{eff} = (2Z_1 + Z_0)/3$

v is the velocity of light

Z_{eff} is the effective surge impedance of the line

Z_1 is the positive sequence surge impedance

Z_0 is the zero sequence surge impedance

ω is 2 π x system power frequency (377 rad/s for a 60 Hz system)

Annex A.5 gives equations for the calculation of the peak factor d as function of system parameters. The rate of rise of recovery voltage on the line side (R_L) is given by the following formula, as function of the fault current (I_L) and the line surge impedance (Z):

$$R_L = \sqrt{2}\omega\, I_L\, Z$$

The first peak of TRV seen across the circuit-breaker terminals is the sum of a line-side contribution (e_L) and a source-side contribution (e_S):

$$e = e_L + e_S$$

$$e_L = d(1 - M)\sqrt{2/3}\, E_{max} \qquad kV$$

$$e_S = 2M(T_L - t_d)$$

where t_d is the time delay of TRV on the source side

T_L is the time to peak $T_L = \dfrac{e_L}{R_L}$

M is the ratio of the fault current to the rated short circuit current

E_{max} is the rated maximum voltage (kV)

This rate-of-rise during SLF is significantly higher than the values that are met during terminal fault interruption:

10.8 kV/μs for SLF with I_L = 45 kA, Z = 450Ω and a 60Hz system

8.64 kV/μs for SLF with I_L = 36 kA, Z = 450Ω and a 60Hz system

3 kV/μs for Terminal fault at 60 % of rated breaking current

2 kV/μs for Terminal fault at 100% of rated breaking current

The high rate-of-rise of SLF associated with high fault currents (of 45 kA or higher) can be difficult to withstand by circuit breakers. In order to assist the circuit breaker during the interruption, a phase to ground capacitor, or a capacitor(s) in parallel to the interrupting chamber(s), can be used to reduce the rate-of-rise of recovery voltage (RRRV).

When a phase-to-ground capacitor is used, the reduction of line side RRRV is given by

$$RRRV_L = \frac{Z\omega I_L\sqrt{2}\sqrt{C_L}}{\sqrt{C_L + 2.5C_{add}}}$$

where

$C_L = \dfrac{\lambda X_L}{\omega Z^2}$ is the total line capacitance

C_{add} is the additional phase-to-ground capacitance

5 FIRST POLE-TO-CLEAR FACTOR

The first pole–to-clear factor (kpp) is a function of the grounding arrangements of the system. It is the ratio of the power frequency voltage across the interrupting pole before current interruption in the other poles, to the power frequency voltage occurring across the pole or poles after interruption in all three poles.

For systems with ungrounded neutral, kpp is or tends towards 1.5. Such systems can be met with rated voltages less than 245 kV, however at transmission voltages, i.e. greater than 72.5kV, it is increasingly rare and effective grounding is the norm.

For effectively grounded neutral systems, the realistic and practical value is dependent upon the sequence impedances of the actual earth paths from the location of the fault to the various system neutral points (ratio X_0/X_1). For these systems, the ratio X_0/X_1 is taken to be ≤3.0. Three-phase to ground faults are the basis for rating because it is recognized that three-phase ungrounded faults have a very low probability of occurrence. For voltages, less than 100 kV, the case of three-phase ungrounded faults is uncommon, however the situation is automatically covered in the Standards since a first pole to clear factor of 1.5 is specified to cover three-phase faults in non effectively grounded systems.

For special applications in transmission systems with effectively grounded neutral where the probability of three-phase ungrounded faults cannot be disregarded, a first-pole-to-clear factor of 1.5 may be required.

For rating purposes, two values of the first-pole to clear factor are defined for the three-phase short-circuit condition. The choice between these two values is dependent on the system grounding arrangement:

a) systems with ungrounded neutral: a standardized value for k_{pp} of 1.5 is used;

b) effectively grounded systems: for standardization purposes the value for kpp used is 1.3.

A third condition does exist, this is where the fault is single-phase in an effectively grounded system and the last-pole-to-clear is considered. For this k_{pp} is 1.0.

Generally, it will not be necessary to consider alternative transient recovery voltages as the standard values specified cover the majority of practical cases.

- Formula for the first-pole-to-clear factor

$$k_{pp} = \frac{3X_0}{X_1 + 2X_0}$$

where X_0 is the zero sequence, and X_1 the positive sequence reactance of the system.

If $X_0 >> X_1$, as in ungrounded systems then: $k_{pp} = 1.5$

If $X_0 = 3.0\,X_1$, as in effectively grounded neutral systems then: $k_{pp} = 1.3$

- Equations for the other clearing poles

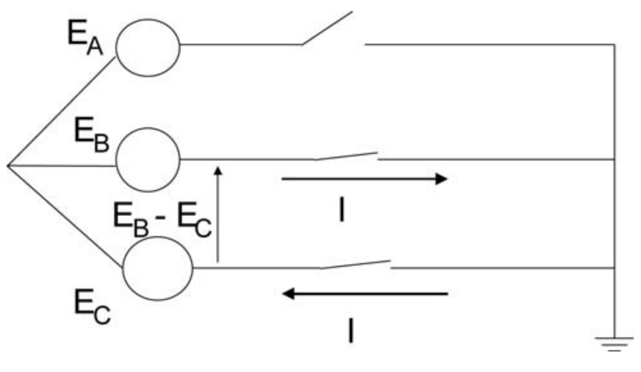

Figure C.1 Ungrounded system after interruption of the first phase

a) Systems with ungrounded neutrals

As illustrated in Figure C.1, after interruption of the first phase (A), the same fault current is carried in phases B and C (but with opposite sign). This current is interrupted by the last two poles in series under the phase-to-phase voltage ($E_B - E_C$) equal to √3 times the phase-to-voltage. Each pole shares $^1/_2$ of the phase-to phase voltage, so that for each pole,

$$k_{pp} = \frac{\sqrt{3}}{2} = 0.87$$

b) Systems with effectively grounded neutrals

In systems with effectively grounded neutrals, the second pole clears a three-phase to ground fault with a factor of

$$k_{pp} = \frac{\sqrt{3}\,\sqrt{X^2_0 + X_0 X_1 + X^2_1}}{X_0 + 2X_1}$$

This formula can be expressed as a function of the ratio X_0/X_1:

$$k_{pp} = \frac{\sqrt{3}\,\sqrt{\alpha^2 + \alpha + 1}}{2 + \alpha} \qquad \text{where } \alpha = X_0/X_1$$

If $\alpha = 3.0$, the second pole to clear factor is 1.25.

For the third pole-to-clear: $k_{pp}=1$

Table C.1 gives k_{pp} for each clearing pole as a function of X_0/X_1 as appropriate.

Table C.1 - Pole-to-clear factors (kpp) for each pole when clearing three-phase to ground faults

neutral	X_0/X_1	Pole-to-clear factor k_{pp}		
	Ratio	First	Second	Third
ungrounded	Infinite	1.5	0.87	0.87
Effectively grounded	3.0	1.3	1.25	1.0
See note	1.00	1..0	1.00	1.0

Note: values of the pole-to-clear factor are given for $X_0/X_1 = 1.0$ to indicate the trend in the special case of networks with a ratio X_0/X_1 of less than 3.0.

It is important to note that as the amplitude factor is the same for each pole, the multiplying factors of table C.1 are applicable to the power frequency voltages and to the TRV on each pole.

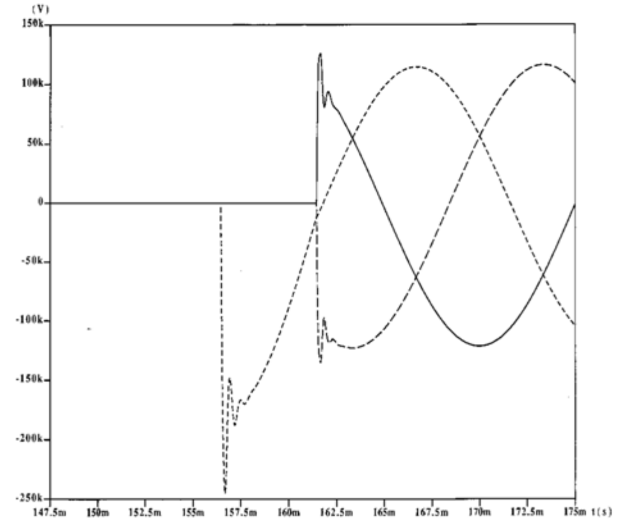

Figure 17 TRV on each pole to clear during a three-phase to ground terminal fault in an ungrounded system.

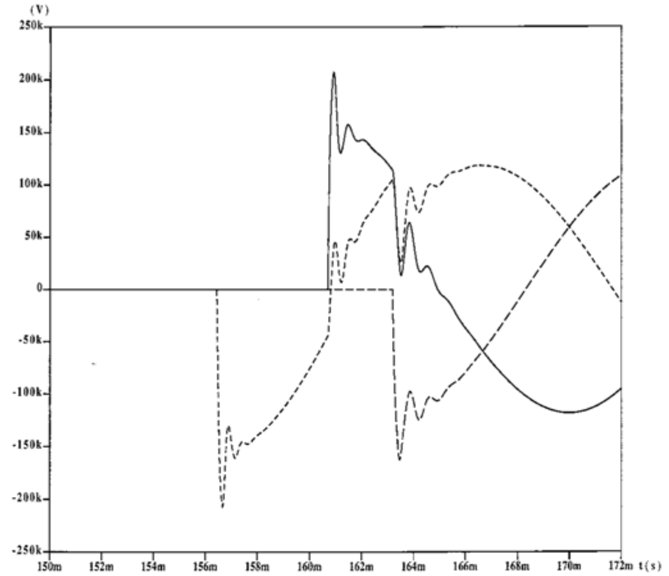

Figure 18 TRV on each pole to clear during a three-phase to ground terminal fault in an effectively grounded system.

In the special case of three-phase ungrounded faults, the pole-to-clear factors are as defined in a) for three-phase faults in ungrounded systems.

- TRV on each pole to clear

Figure 17 shows the TRV on each pole to clear during interruption of a three-phase to ground terminal fault in an ungrounded system. The same TRV would be applied in the case of a three-phase ungrounded fault.

Figure 18 shows currents and TRV on each pole to clear during interruption of a three-phase to ground terminal fault in an effectively grounded system.

6 RATING AND TESTING

6.1 TERMINAL FAULT

The TRV ratings for circuit breakers are applicable for interrupting three-phase to ground faults at the rated symmetrical short circuit current and at the maximum rated voltage of the circuit breaker. For values of fault current other than rated and for line faults, related TRV capabilities are given. Rated and related TRV capabilities are described in ANSI/IEEE Std C37.04 and given in detail in ANSI C37.06.

While three-phase ungrounded faults produce the highest TRV peaks, the probability of their occurrence is very low. Therefore, as described in ANSI/IEEE Std C37.04, the TRV ratings are based on three-phase grounded faults with the TRV peaks established based on the grounding arrangements prevalent at the respective system voltages.

For circuit breakers applied on systems 72.5 kV and below, the TRV ratings assume that the systems can be operated ungrounded. The first pole-to clear factor k_{pp} is 1.5.

For circuit breakers applied on systems 245 kV and above, the TRV ratings assume that the systems are all operated effectively grounded: the first pole-to-clear factor k_{pp} is 1.3. For systems 100 through 170 kV the systems can be operated either ungrounded or effectively grounded so two TRV ratings are available for these systems (k_{pp} = 1.3 or 1.5). In addition, for special applications in transmission systems where the probability of three-phase ungrounded faults cannot be disregarded, a first pole-toclear factor of 1.5 may be required.

The two-parameter and four-parameter envelopes, illustrated in Figures 19 and 20, have been introduced in ANSI/IEEE Std C37.04 in order to facilitate the comparison of a TRV obtained during testing and a specified TRV. In a similar way it is possible to compare a circuit-breaker specified TRV capability and a system TRV obtained by calculation.

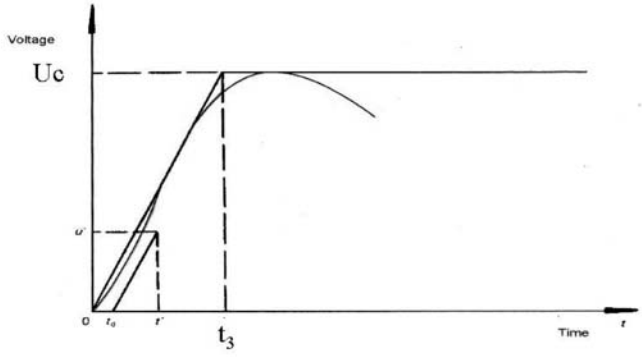

Figure 19 - Example of inherent test TRV with two-parameter envelope

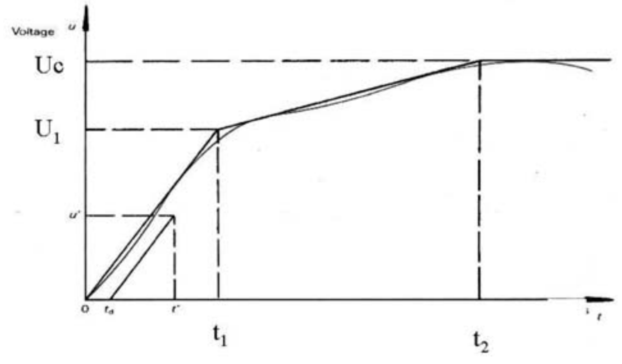

Figure 20 - Example of inherent test TRV with four-parameter envelope

Two-parameter and four-parameter envelopes are used respectively for oscillatory (underdamped) and exponential (damped) TRVs. For standardization purposes, two-parameter envelopes are specified for circuit breakers rated less than 100 kV, at all values of breaking current, and for circuit breakers rated 100 kV and above if the short-circuit current is equal or less than 30% of the rated breaking current. Four-parameter envelopes are specified in other cases.

The peak value of TRV is defined as follows

$$u_c = k_{pp} \times k_{af} \times \sqrt{2/3} \times Ur$$

where

k_{pp} is the first pole to clear factor (see section 7).

k_{af} is the amplitude factor (ratio between the peak value of TRV and the peak value of the recovery voltage at power frequency)

Typical values of k_{af} are 1.4 and 1.7 respectively at 100% and 10% of rated breaking current.

A circuit breaker TRV capability is considered to be sufficient if the two or four parameter envelope drawn with rated parameters is higher than the two or four parameter envelope of the system TRV. This procedure is justified as it allows comparison of the circuit breaker TRV capability and the system TRV in the two regions where a reignition is likely, i.e. during the initial part of the TRV where the RRRV is maximum and in the vicinity of the peak voltage (u_C). Generally, if the circuit breaker can withstand the initial TRV rate of rise, and the TRV peak, it will successfully interrupt. These are the most critical areas to check.

The general characteristics of the TRV envelopes defined by ANSI/IEEE Std C37.04 are illustrated in Figures 21 and 22 as a function of the fault current magnitude.

As explained in section 2, the rate-of-rise of recovery voltage (RRRV) decreases when the short-circuit current is increased. For circuit-breakers rated 100 kV and above, standard values of RRRV are 2kV/μs and 3 kV/μs respectively for terminal fault tests at 100 % and 60 % of rated short-circuit current.

Tests are required at 100%, 60%, 30% and 10% of rated short-circuit current with the corresponding TRVs and recovery voltages [8].

Tests are generally performed with symmetrical and asymmetrical currents, as both conditions are possible in service. However when interrupting asymmetrical currents, the rate-of-rise and peak value of TRV are reduced (see annex A.6).

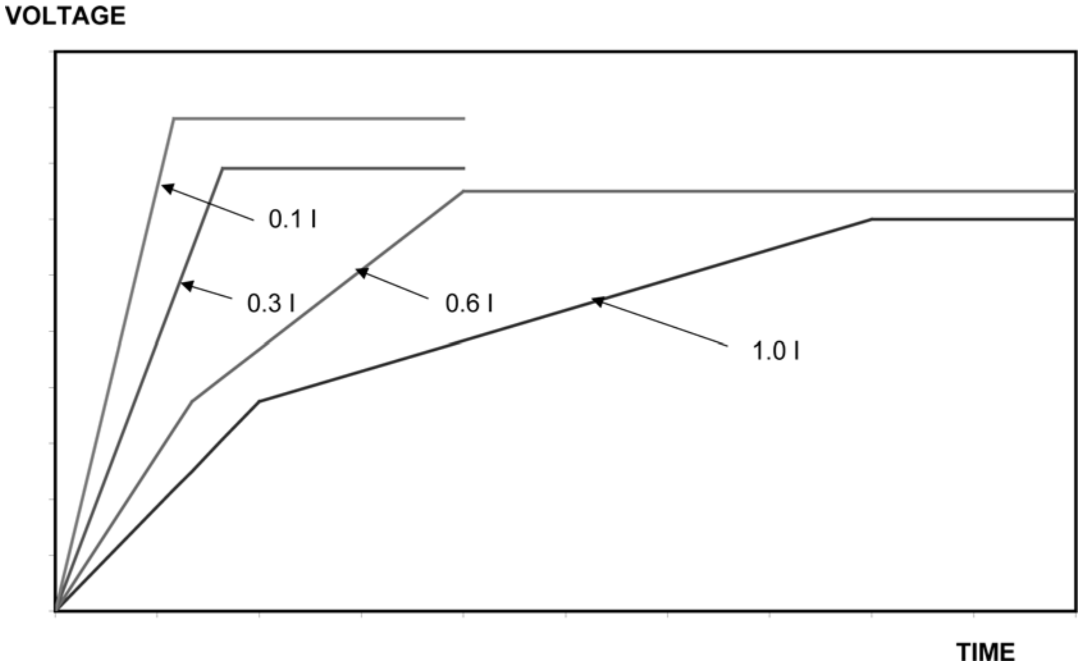

Figure 21 - TRV envelopes, 100 kV and above (I is the rated short-circuit current)

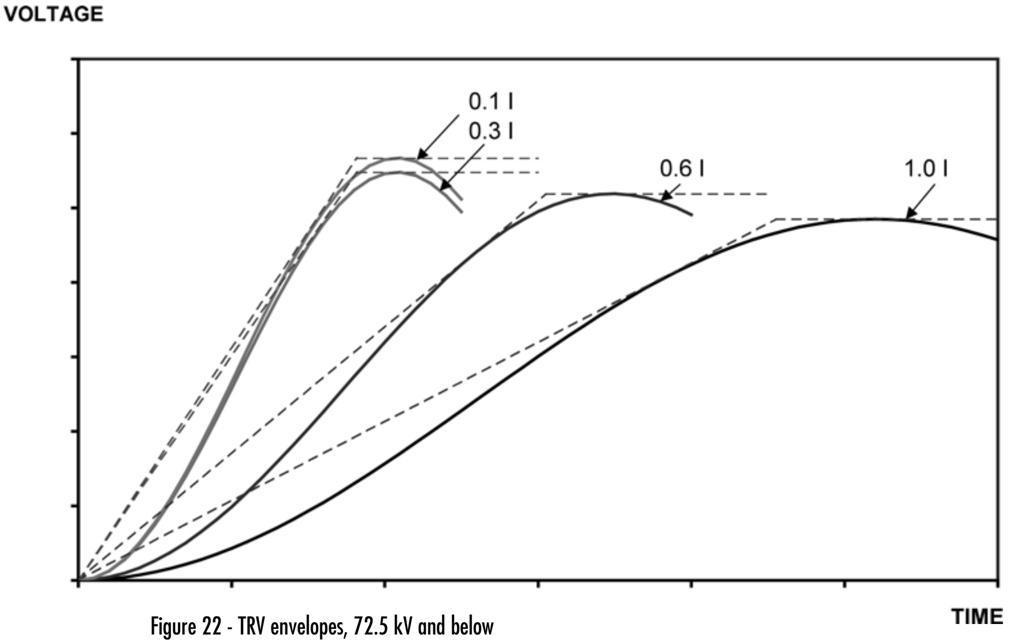

Figure 22 - TRV envelopes, 72.5 kV and below

In a network, the initial part of the TRV may have an initial oscillation of small amplitude, called ITRV, due to reflections from the first major discontinuity along the busbar. The ITRV is mainly determined by the busbar and line bay configuration of the substation. The ITRV is a physical phenomenon that is very similar to the short-line fault (see 6.2). Compared with the short-line fault, the first voltage peak is rather low, but the time to the first peak is extremely short, within the first microseconds after current zero. If a circuit breaker has a short-line fault rating, the ITRV requirements are considered to be covered. Since the ITRV is proportional to the busbar surge impedance and to the current, the ITRV requirements can be neglected for all circuit-breakers with a rated short-circuit breaking current of less than 25 kA and for circuit breakers with a rated voltage below 100 kV. In addition, the ITRV requirements can be neglected for circuit breakers installed in metal enclosed gas insulated switchgear (GIS) because of the low surge impedance.

6.2 SHORT LINE FAULT

The rated values for the line surge impedance Z and the peak factor d as defined in ANSI/IEEE Std C37.04 are as follows:

$Z = 450\Omega$

$d = 1.6$

The line side contribution to the initial part of TRV is defined as a triangular wave in ANSI/IEEE Std C37.09 as follows:

$$e_L = d(1 - M)\sqrt{2/3}\,U_r \quad kV$$
$$R_L = \sqrt{2}\,\omega\,M\,I\,Z.10^{-6} \quad kV/\mu s$$
$$T_L = e_L/R_L \quad \mu s$$

where
e_L is the peak value of TRV on the line side (kV)
R_L is the rate-of-rise (kV/μs)
T_L is the time to peak (μs)
M is the ratio of the fault current to the rated short circuit current
U_r is the rated maximum voltage (kV)
I is the rated short circuit current (kA)

As can be seen in Figure 14, the TRV across the interrupter is in reality the difference between the transient recovery voltages on the supply and on the line side. As illustrated in Figure 23, the variation of the source side voltage increases the first peak value of TRV by e_S.

$$e_{total} = e_s + e$$

As a first approximation, the contribution from the source side voltage can/ be estimated by considering that the variation of the source side voltage is zero until time $td = 2\mu s$ (standard value of time delay), and then changes with a slope of 2 kV/μs (standard value of *RRRV* for terminal fault) up to time T_L.

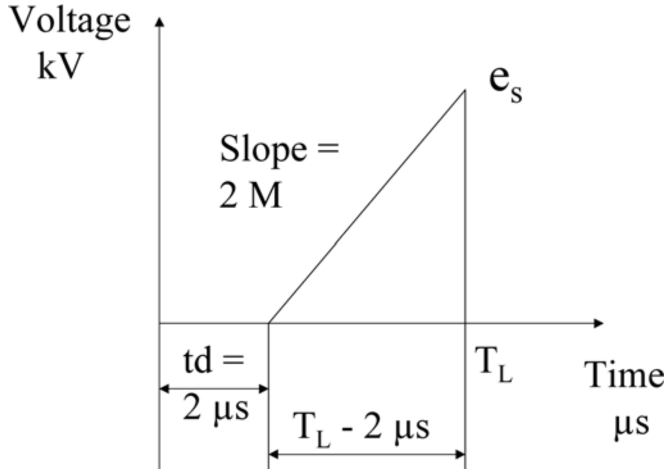

Figure 23 - Contribution of the source side voltage on TRV

In this approximation, it is considered that the *RRRV* is the same as for three-phase terminal faults. In reality it is reduced by the factor *M* as *RRRV* is proportional to the fault current (on the source side *RRRV* = 2 × *M*).

$$e_s = (T_L\text{-}2\mu s) \times 2M$$

Tests are required at 90% and 75% of rated short-circuit current with the corresponding TRVs and recovery voltages [8].

6.3 OUT-OF-PHASE

TRVs for out-of-phase conditions are specified as for terminal fault, except that the pole to clear factor is equal to 2.0 and 2.5 respectively for systems with effectively grounded neutral and for systems with ungrounded neutral.

Tests are required at 25% and 5-10% of rated short-circuit current with the specified TRV and recovery voltage [8].

7 APPLICATION CONSIDERATIONS

IEEE C37.011 (under revision) covers procedures and calculations necessary to apply the standard TRV ratings for ac high-voltage circuit breakers rated above 1000 V.

7.1 TRANSFORMER FED FAULT

The standard capability curve, shown in Figure 24, is defined by a two-parameter envelope where uc and t3 are defined in tables 3 and 6 of ANSI C37.06 (with 10% and 30% of rated short-circuit current).

Severe TRV conditions may occur in some cases, for instance when short-circuit occurs immediately after a transformer without any appreciable additional capacitance between the transformer and the circuit breaker. In such cases, both the peak voltage and rate-of-rise of transient recovery voltage may exceed the values specified in ANSI/IEEE Std C37.06 (see Figure 12). Such cases are covered by the TRV ratings fast time-to-peak values for definite purpose circuit breakers given in ANSI C37.06.1-2000.

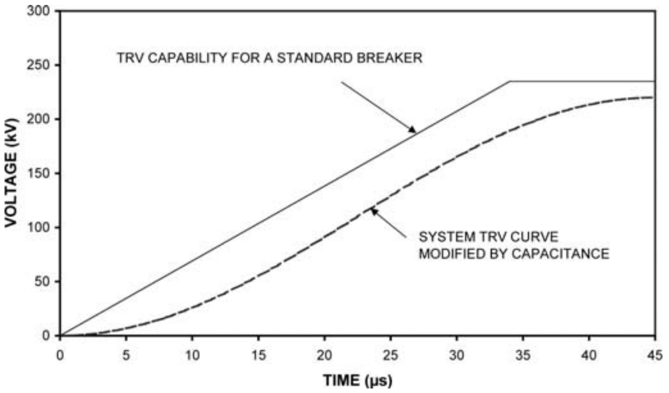

Figure 24 Comparison of TRV capability for 145 kV circuit breaker (at 10% of its rated interrupting current capability) and system TRV modified by additional capacitance between circuit breaker and transformer

These values should be specified only when the rate of rise of the system TRV is higher than the rate of rise of the standard capability curve defined in ANSI C37.06.

The system TRV curve can be modified by a capacitance and then be within the standard capability envelope. Figure 24 illustrates the modified system TRV for the condition of Figure 12, but with additional capacitance assumed between the transformer and the circuit breaker.

The contribution of transformers to the short-circuit current is relatively larger at smaller values of short-circuit current as in T30 and T10 conditions. However, most systems have effectively grounded neutrals at ratings of 100 kV and above. With the system and transformer neutrals effectively grounded, the first-pole-to-clear factor of 1.3 is applicable for all terminal fault test duties. In some systems for rated voltages of 100 kV up to including 170 kV, transformers with ungrounded neutrals are in service, even though the rest of the system may be effectively grounded. Such systems are considered special cases and are covered in ANSI/IEEE C37.04 and ANSI C37.06 where test duties.

T30 and T10 are based on a first-pole-to-clear factor of 1.5. For rated voltages above 170 kV, all systems and their transformers are considered to have effectively grounded neutrals.

For currents between 10% and 30% of rated short-circuit current, values of u_c and t_3 can be obtained by linear interpolation.

7.2 SERIES REACTOR LIMITED FAULT

Series reactors are used to limit the short-circuit current in a line. When line side series reactors are used, high rate-of-rise TRVs can result in much the same ways as for transformer limited faults.

An example of a series reactor used on a 230 kV system is illustrated in Figure 25. The resultant TRV for the case described is shown in Figure 26. The same TRV is obtained if the reactor is on the bus side of the circuit breaker and the fault is on the line side of the circuit breaker.

This system TRV may exceed the standard capability curve, which is described by a two-parameter envelope where u_c and t_3 are defined in ANSI C37.06 for 10% short-circuit breaking capability, maximum voltage (E_{max} = 245 kV)

$$u_c = 398\ kV$$

$$t_3 = 57\ \mu s$$

For currents between 10% and 30% of rated short-circuit current, values of u_c and t_3 can be obtained by linear interpolation.

Wavetraps used in transmission line communication systems may also add a high frequency component to the TRV although of a lesser magnitude than a transformer or a current limiting reactor. However, under some circumstances, wavetraps can substantially increase the TRV over that present without the trap. A wavetrap is usually a parallel L-C device that is placed between the line and circuit breaker.

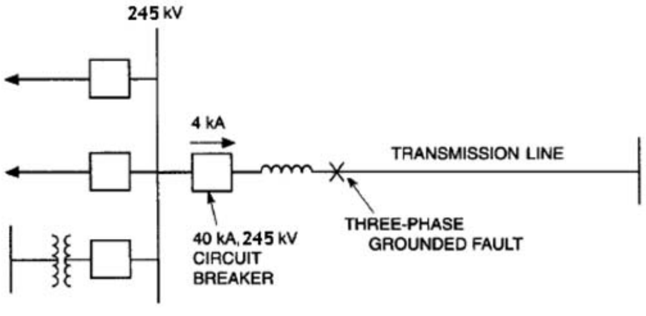

Figure 25 – Series reactor limited fault

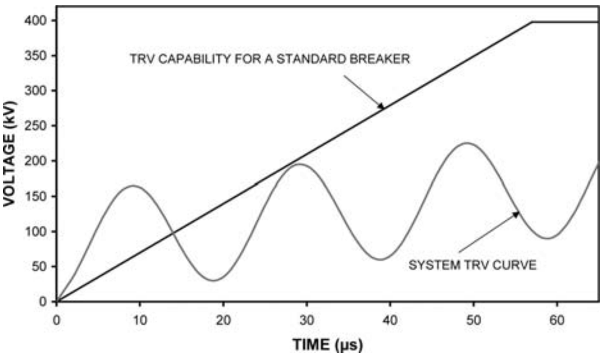

Figure 26 - Comparison of TRV capability for 245 kV circuit breaker (at 10% of its rated interrupting current capability) and system TRV

When the system TRV exceeds a standard breaker capability, the user has two possibilities:

- specify a Definite Purpose circuit breaker for fast transient recovery voltage rise times, as defined in ANSI C37.06.1-2000. In some cases their higher TRV withstand capability will be sufficient.

- Add a capacitance in parallel to the reactor in order to reduce the TRV frequency and have a system TRV curve within the standard capability envelope.

7.3 SHUNT REACTOR SWITCHING

When switching a shunt reactor, a circuit breaker interrupts an inductive current of small amplitude. As a first approximation, the load can be simulated by an inductance L_1 in parallel with a capacitance C_1 (Figure 27a).

An ideal circuit breaker, i.e. without arc voltage, interrupts at current zero, at a time when the supply and load voltages are maximum (Figure 27b).

After interruption, the load side voltage oscillates towards zero with a frequency

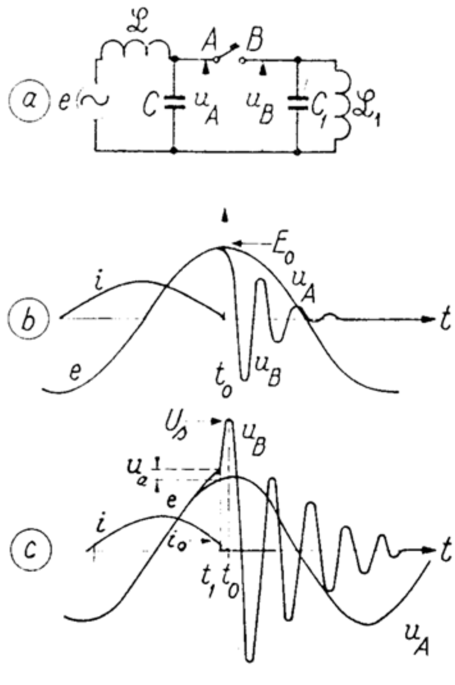

Figure 27 Shunt reactor current interruption a) Simplified circuit
b) Interruption without arc voltage c) Interruption with current chopping

$$f_L = \frac{1}{2\pi}\sqrt{L_1 C_1}$$

and the supply side voltage varies at power frequency, like the source voltage. The TRV is the difference between the load side and the supply side voltages.

As the frequency f_L is typically in the range 1 to 5 kHz, reignitions are possible when the circuit breaker interrupts with short arcing times. These reignitions can lead to overvoltages.

During interruption, current can be forced prematurely to zero due to arc instability. This phenomenon called current chopping can also generate overvoltages (Figure 27c).

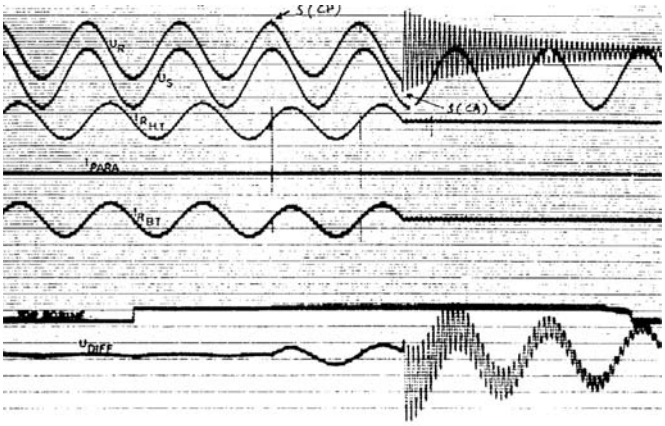

Figure 28 Interruption of shunt reactor current
Upper trace = load side voltage Lower trace = TRV

Overvoltages can be limited to acceptable values when one of the following methods is used:

- synchronised switching,
- metal oxide varistor across the circuit breaker terminals,
- opening resistor.

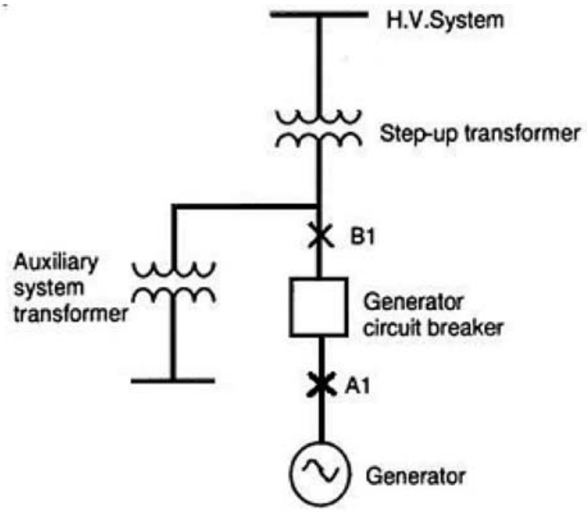

Figure 29 Fault conditions for Generator circuit breakers
A1 System-source fault B1 Generator-source fault

Figure 28 shows interruption of a 55 MVAR shunt reactor current by an air-blast circuit breaker with opening resistor in the 735 kV network of Hydro-Québec.

Limitation of overvoltages and circuit breaker specification are covered in ANSI/IEEE Standard C37.015 [11].

7.4 GENERATOR CIRCUIT BREAKERS

Special TRV requirements are applicable for generator circuit breakers installed between a generator and a transformer.

As illustrated in Figure 29, two types of faults need to be considered.

For the two types of faults, the TRV has an oscillatory waveshape and the first pole-to-clear factor is 1.5 in order to cover three-phase ungrounded faults.

TRV parameters, i.e. peak voltage uc, rate-of-rise (RRRV) and time delay, are listed in ANSI/IEEE C37.013.

- TRV for system-source faults

RRRV for system-source faults is 3-5 times higher than the values specified for distribution or sub-transmission circuit breakers. This is due to the fact that the TRV frequency is dominated by the natural frequency of step-up transformer if one considers the more severe case where the capacitance on the high side of the transformer can be neglected.

After reviewing the available transformer data of many power plants, the IEEE standardization group has defined TRV parameters in several ranges of transformer rated power.

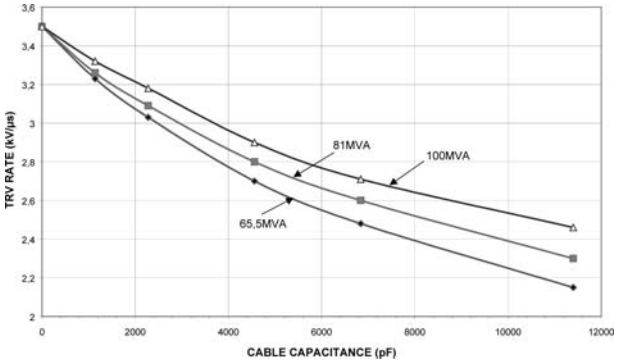

Figure 30 RRRV for system-source faults – Transformers 50 MVA to 100 MVA

The RRRV can be significantly reduced if a capacitor is installed between the circuit breaker and the transformer. It is also reduced in the special cases where the connection between the circuit breaker and the transformer(s) is made by cable(s) [14]. This will be covered in an amendment to ANSI/IEEE C37.013.

TRV RATE FOR SYSTEM FED FAULTS
TRANSFORMER 50MVA<<=100MVA

- TRV for generator-source faults

RRRV for generator-source faults is roughly 2 times higher than the values specified for distribution or sub-transmission circuit breakers. The values were defined after reviewing the data of many generators.

Standardized values are currently revised to cover applications with generators rated 10 to 100 MVA.

Due to the large time constants of generators and transformers (high X/R), Generator circuit breakers are required to interrupt currents with a high percentage of DC component (high asymmetry). The rate of rise and peak value of TRV during interruption of currents with large asymmetry are reduced as explained in annex A.6.

7.5 SELECTION OF A CIRCUIT BREAKER

The TRV ratings define a withstand boundary. A circuit TRV that exceeds this boundary at rated short circuit current, or the modified boundary for currents other than rated, is in excess of the circuit breaker's rated or related capability. Either a different circuit breaker should be used, or the system should be modified in such a manner as to change its transient recovery voltage characteristics when the withstand boundary is exceeded. The addition of capacitors to a bus or line is one method that can be used to improve the system's recovery voltage characteristics. In special cases where the terminal fault TRV capability at 60% or 100% of short-circuit capability is higher than rated, a breaker with a higher rated interrupting capability could be used (see ANSI/IEEE C37.011).

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ANNEX A

A.1 THREE-PHASE TERMINAL FAULT

During the interruption of a three-phase terminal fault, the circuit shown in Figure A.1 defines the general electrical equivalent network for the first phase to clear. The reduced circuits are valid for short time frames until reflections return from remote buses. Reflections are covered in A.4.

Figure A.1a) shows the corresponding one-line diagram representations, while Figure A.1b) indicates the three-phase representation.

The equivalent circuit given by Figure A.1c) shows that it is reduced to a simple parallel RLC circuit with components defined as follows:

- Equivalent inductance

$$L_{eq} = \frac{3L_0L_1}{L_1+2L_0} \qquad \text{(A–1)}$$

For three-phase to ground faults in effectively grounded systems, i.e. with $L_0 = 3L_1$,

$L_{eq} = 9\ L_1/\ 7 = 1.3\ L_1$

For three-phase to ground faults in ungrounded systems (L_0 infinite), $L_{eq} = 1.5\ L_1$

- Equivalent surge impedance

$$L_{eq} = \frac{3}{n}\frac{Z_0Z_1}{Z_1+2Z_0} \qquad \text{(A–2)}$$

where $Z_0 = 1.6\ Z_1$

$Z_{eq} = 1.14\ Z_1\ /\ n$

- Equivalent capacitance

$C_{eq} = C_0 + 2(C_1–C_0)/3=(C_0+ 2C_1)/3$

if $C_0 = C_1$ then $C_{eq} = C_0 = C_1$

where

Z_1 is the positive-sequence surge impedance of the transmission lines terminating at the station

Z_0 is the zero-sequence surge impedance of the transmission lines terminating at the station

n is the number of lines

L_1 is the positive-sequence inductance, representing all other parallel sources terminating at the station (transformation to lower or higher voltage systems, generation, etc.)

L_{0-} is the zero-sequence inductance, representing all other parallel sources terminating at the station

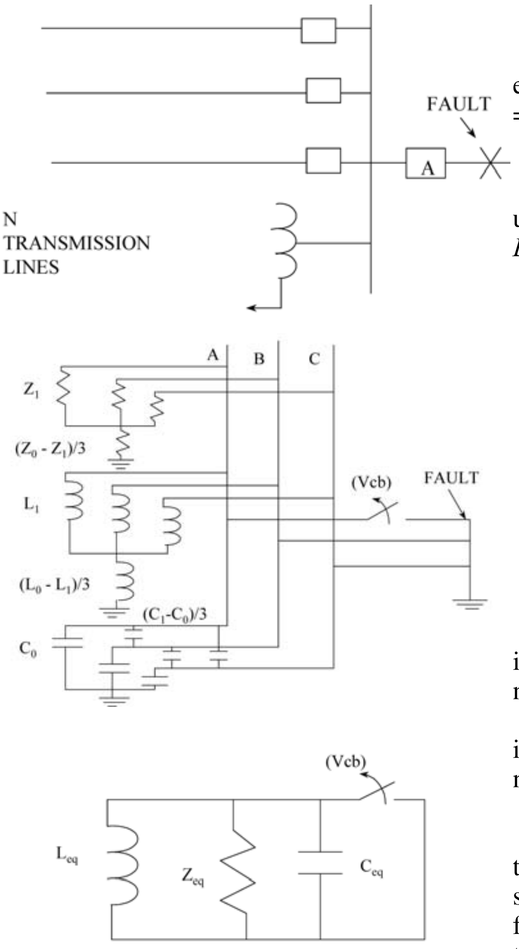


Figure A.1— Circuit definition—interruption of a three-phase to ground fault

C_1 is the positive-sequence capacitance
C_0 is the zero-sequence capacitance

For the special case of three-phase ungrounded faults on effectively grounded systems, $L_{eq} = 1.5\ L_1$, $Z_{eq} = 1.5\ Z_1/n$, $C_{eq} = 2/3\ C_1$.

ANSI/IEEE C37.011 provides methods for the determination of parameters (such as L_1) and gives typical values of Z_1, Z_0 and capacitances of various equipment.

A.2 EXPONENTIAL (OVERDAMPED) TRV

Current injection techniques can be used to solve for the circuit breaker TRV and, because the time span of interest is short (microseconds), the interrupted current can be represented by a ramp. The solution for the parallel RLC network as shown in Figure A.1c) is

$$V_{cb} = E_1\ (1\text{-}e^{-\alpha t}\ (\cosh\beta t + \alpha/\beta\ \sinh\beta t\ ))\quad kV \qquad \text{(A-3)}$$

where
V_{cb} is the voltage across the open circuit breaker contacts
E_1 is $\sqrt{2}\ I\omega\ L_{eq}$ in kV
ω is $2\ \pi$ f= 377 rads for 60Hz systems
I is short circuit current in kA, rms
α is $1/(2Z_{eq}C_{eq})$
β is $\sqrt{\alpha^2\text{-}1/(L_{eq}C_{eq})}$
Z_{eq} is in ohms
L_{eq} is in henrys
C_{eq} is in farads

For many systems, the circuit will be overdamped by the parallel resistance of the line surge impedances, thus the capacitance can be neglected as a first approximation. The solution to the simple RL circuit is then

$$V_{cb} = E_1\ (1 - e^{-t/\tau})\qquad kV \qquad \text{(A-4)}$$

where
τ is L_{eq}/Z_{eq} s

The derivative of equation (A-4) at time zero is the rate of rise of the recovery voltage and is given by

$$dV_{cb}\ /dt = R = \sqrt{2}\ I\ \omega\ Z_{eq}\qquad 10^{-6}\ kV/\mu s \qquad \text{(A-5)}$$

The above exponential expressions [see equations (A-3), (A-4), (A-5)] describe the component of the TRV until reflections return from remote stations associated with the transmission lines connected to the faulted station.

A.3 OSCILLATORY (UNDERDAMPED) TRV

If there are no lines on the bus, then the resistance is removed from the equivalent circuit in Figure A.1c), and the TRV will be oscillatory. An approximate expression for the voltage is given in equation (A-6). The expression is approximate because of neglecting the source impedances behind the transformers.

$$V_{cb} = E_1[1\text{-}\cos(t/\sqrt{L_{eq}C_{eq}})]\quad kV \qquad \text{(A-6)}$$

Even when lines are present, it is possible for the recovery voltage to be oscillatory. To be oscillatory, the surge impedance of a source side line has to be such that

$$Z_{eq} \geq 0.5\sqrt{L_{eq}/C_{eq}}$$

With Zeq, Leq and Ceq as defined in A.1.

This formula shows that as the number of transmission lines is increased, the circuit is likely to be nonoscillatory, i.e., overdamped. In most cases, however, even N=1 makes the circuit overdamped.

A.4 REFLECTED WAVES

The initial wave that was calculated in equation (A-4) appears across the breaker pole. It also appears as traveling waves on each of the transmission lines. When one of these waves reaches a discontinuity on the line such as another bus or a transformer termination, a reflected wave is produced, which travels back towards the faulted bus. The time for a wave to go out and back to a discontinuity is

$$T = 6.65\ l\ \sqrt{\mu k}\qquad \mu s \qquad \text{(A-7)}$$

l is the distance to the first discontinuity (in kilometer)
μ is the magnetic permeability
k is the dielectric constant

for overhead lines

$\sqrt{\mu k} = 1.0$ and Z_1 about 400 ohms (less for bundled conductor $250 < Z_1 < 350$) for cables, typically

Paper insulated fluid filled k=4, μ =1.0 and $\sqrt{\mu k}$= 2

PPP insulated fluid filled or EPR k=3, μ=1.0 and $\sqrt{\mu k}$ =1.73

Polyethylene k =2.3, μ =1.0 and $\sqrt{\mu k}$=1.52

Cable Surge Impedance (ohms) $20 < Z_1 < 50$

At a discontinuity transmitted and reflected waves can be described by equations (A-8) and (A-9) and Figure A.2.

Transmitted wave

$$e_t = e_i\ [2Z_b/(Z_a + Z_b)] \qquad \text{(A-8)}$$

Reflected wave

$$e_r = e_i\ [(Z_b\ \text{-}Z_a)/Z_a + Z_b)] \qquad \text{(A-9)}$$

where
e_i is the incident wave
Z_a and Z_b are the equivalent surge impedances on either side of the discontinuity

Returning to the bus, the reflections are, in turn, reflected to begin the process again. A typical TRV, including the first reflection, is shown in Figure A.3. A reflected wave returning from an open ended line will contribute to the bus side TRV as follows:

$$E_{rl} = E_1\ (2\ Z_{eq}\ t/L_{eq})\ e^{-Z_{eq}\ t/L_{eq}}\quad kV \qquad \text{(A-10)}$$

where $\quad Z_{eq} = Z_a = 1.14\dfrac{Z_1}{n}$ and $L_{eq} = \dfrac{3L_0L_1}{L_1+2L_0}$

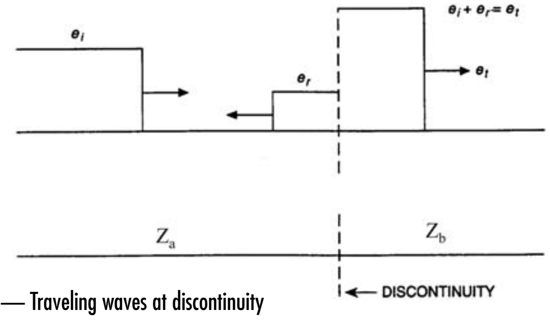


Figure A.2— Traveling waves at discontinuity

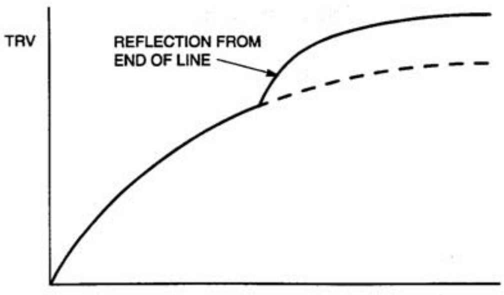


Figure A.3— Typical TRV including the first reflection

From (A-10) it can be shown that the maximum reflected voltage is $E_{rl}\max = 0.7\ E_1/n$. The more lines connected, the lower the magnitude of the reflected wave.

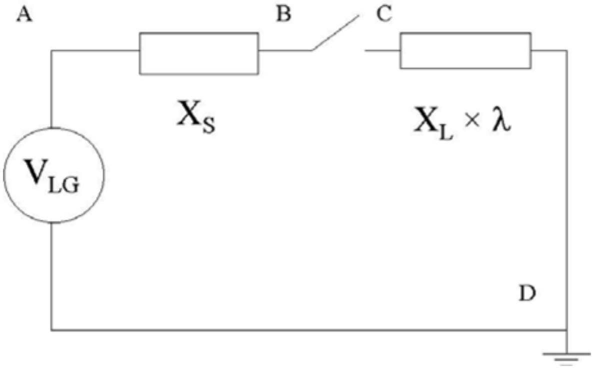


Figure A.4 Single-phase circuit with short-line fault

A.5 SHORT-LINE FAULT

Figure A.4 illustrates the single-phase circuit where the short-circuit current is limited by the source reactance (X_S) in series with the line reactance ($X_L\ \lambda$):

The fault current is given by:

$$I_L = \frac{V_{LG}}{X_L\lambda + X_S}$$

The source side reactance is given by

$$X_S = \frac{V_{LG}}{I_T}$$

The fault current is then

$$I_L = \frac{V_{LG}}{X_L\lambda + V_{LG}/I_T} \qquad \text{(A-11)}$$

where

X_L is $(2\ L_{1w} + L_{0w})\ \omega / 3$ (A-12)

X_L is the reactance of the line to the fault point per unit length

L_{1w} is the positive sequence power frequency line inductance per unit length

L_{0w} is the zero sequence power frequency line inductance per unit length

V_{LG} is the system line-ground voltage

λ is the distance from the opening circuit-breaker to the fault

A.5.1 Calculation of peak factor (d)

The peak factor (d) is the ratio of amplitudes of the first peak of the TRV (UL = VCDo + VCDp as shown on Figure 14) to the peak voltage on the line side prior to interruption (Uo = VCDo):

$$d = U_L / U_0 \qquad \text{(A-13)}$$

The rate of rise (*R*) of the line side TRV is equal to the effective line surge impedance (Z_{eff}) multiplied by the slope of current at current zero (*di/dt*) as follows:

$$R = \sqrt{2}\ \omega\ I_L\ Z_{eff}$$

with $di/dt = \sqrt{2}\omega\ I_L$

The time to the first peak U_L is equal to two times the travel time from the circuit breaker to the fault point (time necessary for the traveling wave to reach the fault and be reflected back to the circuit breaker) : $2\lambda / v = t_L$

where

λ is the distance from the opening circuit-breaker to the fault

v is the velocity of light

It follows that the first peak of the line side TRV is given by :

$$U_L = Z_{eff}\ di/dt\ 2\lambda / v \qquad \text{(A-14)}$$

$$U_0 = X_L\ \lambda\ I_L\sqrt{2} \qquad \text{(A-15)}$$

From (A-13), (A-14) and (A-15):

$$d = 2\omega \frac{Z_{eff}}{X_L\ v} \qquad \text{(A-16)}$$

where

$X_L = (2\ L_{1w} + L_{0w})\ \omega / 3$

$Z_{eff} = (2Z_1 + Z_0)/3$ (A-17)

$Z_1 = \sqrt{L_1/C_1}$ (A-18)

$v = 1/\sqrt{L_1 C_1}$ (A-19)

Z_1 = positive sequence surge impedance

Z_0 = zero sequence surge impedance

L_1 = high-frequency positive sequence line inductance per unit length

C_1 = high-frequency positive sequence line capacitance per unit length

The effective surge impedance Z_{eff} is influenced by bundle and tower configuration.

From (A-18) and (A-19):

$$Z_1 / v = L_1 \qquad \text{(A-20)}$$

From (A-16), (A-17), (A-18) and (A-20):

$$d = 2\omega \frac{(2Z_1 + Z_0)L_1}{(3Z_1)(2L_{1\omega} + L_{0\omega})} \frac{3}{\omega}$$

or

$$d = 2\,\frac{(2 + Z_1/Z_0)L_1}{(2L_{1\omega} + L_{0\omega})} \qquad \text{(A-21)}$$

Table A.1— Typical surge impedances

	System (kV)	Z_0 (Ohms)	Z_1* (Ohms)	Z_{eff}‡ (Ohms)
Overhead lines	145	560	350	420
	245	525	375	425
	362	430**	280**	330**
	550	430**	280**	330**
	800	400**	265**	310**
Cables	72.5 145 245 362		Cable surge impedance depends on the cable type and configuration. Typically Z_1 and Z_{eff} range from 50 to 75 Ω with $Z_1 \cong Z_{eff}$	
SF_6 buswork	All voltages		55	55

* Used for three-phase grounded terminal faults

** Bundled conductors assumed for 362 kV class lines and above

‡ Used for short line faults where Zeff = (2 Z1 + Z0)/3 and Z0 is determined at switching surge frequencies.

These values do not take into account conductor clashing. Calculations performed on 420 kV lines have shown that the effective surge impedance is between 434W and 450W when bundle contraction during fault is considered.

If the high-frequency inductance L_1 is equal to the power frequency inductance of the line $L_{1\omega}$, formula (A-21) simplifies to:

$$d = 2\,\frac{(2+Z_1/Z_0)}{(2+L_{0\omega}/L_{1\omega})} \qquad \text{(A-22)}$$

if $L_{0\omega}/L_{1\omega} \approx 3$ is assumed for high-voltage networks:

$$d = 0.4\,(2+Z_0\,/\,Z_1) \qquad \text{(A-23)}$$

In practice, the high frequency inductance L_1 is lower than the power frequency value $L_{1\omega}$., and losses which are always present have been neglected in the calculation. For these reasons the peak factor value obtained by (A-23) is conservative.

As the ratio Z_0/Z_1 is always lower than 2 for HV networks, 72.5 kV to 550 kV, values of the peak factor (*d*) is equal or lower than 1.6. Therefore the standardized value of 1.6 is conservative.

Using (A-17) and (A-23) the peak factor is

$$d = 1.2Z_{eff}/Z_1$$

Typical values of Z_{eff} and Z_1 are given in Table A.1 taken from ANSI/IEEE C37.011.

The line side recovery voltage crest is then equal to

$$U_L = dU_0 = dX_L\,\lambda\,I_L\sqrt{2} \qquad \text{(A-24)}$$

A.5.2 Graphical determination of line side voltages by traveling waves

At the time of interruption (t= 0) the instantaneous voltages on the circuit breaker terminals (points B and C in figure A.4) are at a maximum. The voltage decreases linearly along the line and is zero at the location of the fault (point D).

As shown on the upper part of Figure A.5, the voltage distribution can be considered as the sum of two waves, of equal amplitude, that are traveling in opposite directions.

In accordance with the theory given in A.4, when a traveling wave reaches the open circuit (Fig A.4 point B), the reflected wave is of same amplitude and with the same polarity.

When a traveling wave reaches the short-circuit (fig A.4 point D), the reflected wave is of the same amplitude as the incident wave but of opposite polarity.

The application of these two basic rules leads to Figure A.5 which shows the distribution of voltages on the faulted line

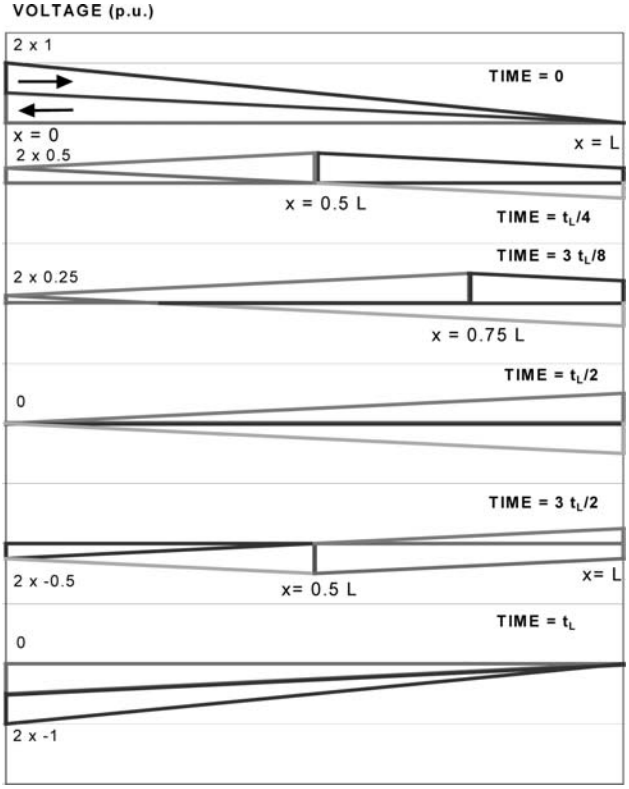


Figure A.5 Traveling waves on a faulted line after current interruption
Views in space with time "frozen"
Blue = wave (or second reflection) moving to right
Light Blue = first reflection of blue wave moving to left
Red = wave or second reflection moving to left
Pink = first reflection of red wave moving to right

at times 0, $t_L/4$, $3t_L/8$, $t_L/2$, $3t_L/4$ and t_L. Time t_L represents the time necessary for the traveling wave to reach the fault and be reflected back to the circuit breaker.

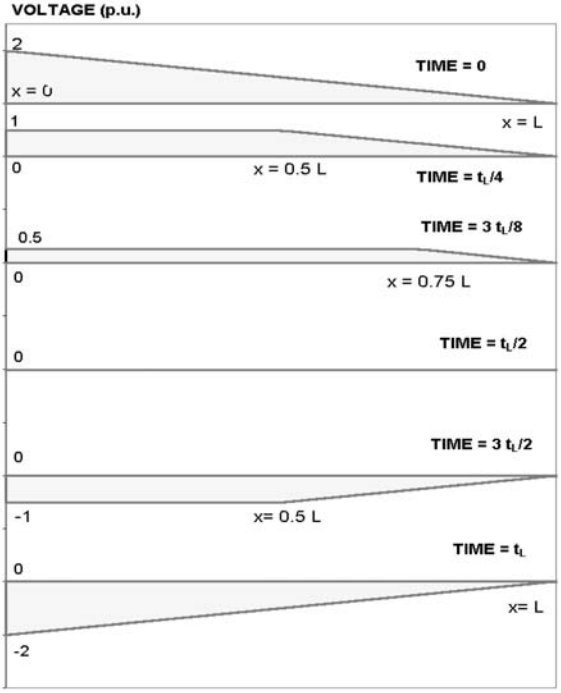


Figure A.6 Voltage distribution on the line at different times after current interruption

The total voltage at each point of the line, and at any given time, is the sum of all waves. Figure A.6 shows the resulting distribution of voltage on the line at several times after current interruption.

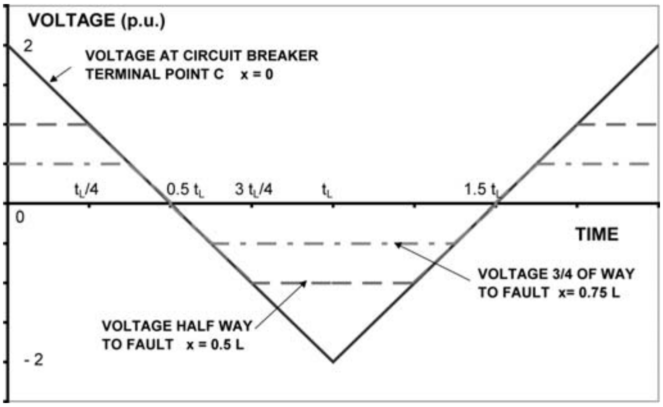


Figure A.7 Time variations of voltages at three locations on the faulted line

Figure A.7 shows the corresponding time-variation of voltages at different locations on the line: at the circuit breaker terminal (fig A.4 point C, (x=0)), half-way to the fault (x=0.5L) and three-quarters of the way to the fault (x=0.75L).

The voltage at the circuit breaker terminal has the well known triangular waveshape. If the voltage on the supply side terminal (figure A.4 point B) is assumed to be constant, since the TRV frequency on the supply side is very low when compared with the line side TRV, the TRV across the circuit breaker terminals has the waveshape shown on figure 13. The forgoing treatment of short line fault TRV has ignored the effects of damping. Damping occurs due to line losses, and imperfect reflections. The fault is not usually a complete short circuit. The open circuit breaker is not an infinite impedance. (especially in the first microsecond) Damping will give rise to lower peak factors than those used in standards.

A.5.3 Calculation of Short-line fault quantities

In this sub-clause we give practical applications of the theory developed in sections 4 and 6.2.

We consider the case of a 245 kV circuit breaker application in a network with a single-phase shortcircuit current of 40 kA and a power frequency of 60 Hz.

According to the notations in 4 and 6.2, we have

$$V_{LG} = \frac{U_r}{\sqrt{3}} = \frac{245}{\sqrt{3}} = 141.5 \qquad kV$$

$$I = I_T = 40kA$$

A.5.3.1 Calculation of the line length corresponding to a fault with 90% of rated shortcircuit current

$M = 0.9$

$I_L = 0.9\, I_T = 0.9 \times 40 = 36kA$

Source side reactance $\Omega X_S = \frac{V_{LG}}{I_T} = \frac{245}{\sqrt{3}\ 40} = 3.536\Omega$

As explained in section 4 :

$$I = 36 = \frac{V_{LG}}{X_L\,\lambda + X_S} = \frac{245/\sqrt{3}}{X_L\,\lambda + 3.536}$$

it follows that

$$36(X_L\,\lambda + 3.536) = \frac{245}{\sqrt{3}}$$

$$X_L\,\lambda = \frac{245}{36\sqrt{3}} - 3.536 = 3.929 - 3.536 = 0.393\Omega \qquad (1)$$

where

X_L is the reactance of the line to the fault point per unit length

X_L is $(2\, L_{1\omega} + L_{0w})\ \omega/\ 3$

L_1 is the positive sequence power frequency line inductance per unit length

L_0 is the zero sequence power frequency line inductance per unit length

V_{LG} is the system line-ground voltage

λ is the distance from the opening circuit-breaker to the fault

ω is 2 π x system power frequency (377 rad/s for a 60Hz system)

$$X_L = (2L_1 + L_0)\frac{\omega}{3} = \frac{2X_1 + X_0}{3}$$

with

$X_1 = L_1\omega = 0.5\Omega/km$

$X_0 = L_0\omega = 1.2\Omega/km$

$$X_L = \frac{2 \times 0.5 + 1.2}{3} = \frac{2.2}{3}\ \Omega/km \qquad (2)$$

From (1) and (2)

$$\lambda = \frac{0.393}{2.2/3} = \frac{3 \times 0.393}{2.2} = 0.536km$$

A.5.3.2 Calculation of the fault current corresponding to a length of faulted line

In this second example of calculation, we consider the case of a fault 1.5 km away on the line.

$$X_L \lambda = \frac{2.2}{3} 1.5 = 1.1\Omega$$

$$I = \frac{245 / \sqrt{3}}{1.1+3.536} = \frac{141.45}{4.636} = 30.5kA$$

It follows that $M = \frac{30.5}{40} = 0.76$

The fault current is 76% of the maximum (single-phase) short-circuit current.

A.5.3.3 Calculation of the first peak of TRV

In the example A.5.3.1, M is 0.9 i.e. the fault current is 90% of the rated short-circuit current.

a) Contribution of the line side voltage (e)

$$e = d(1\text{-}M)\sqrt{2/3}\,U$$

$$e = 1.6 \times 0.1 \times \sqrt{2/3} \times 245 = 32kV$$

b) Contribution of source side voltage) (e_S)

As explained in sub-clause 6.2, the contribution of the source side voltage is:

$$e_S = 2\,x\;M\,(T_L - 2) \qquad (3)$$

The time to peak T_L is determined as follows:

$$R_L = \sqrt{2}\,\omega\,Z\,M\,I$$

$$R_L = \sqrt{2} \times 377 \times 450 \times 0.9 \times 40\;10^{-6}\;kV/\mu s$$

$$= 0.24 \times 0.9 \times 40\;10^{-6}\;kV/\mu s$$

$$T_L = \frac{e}{R_L} = \frac{32}{8.64} = 3.7\mu s \qquad (4)$$

From (3) and (4):

$$e_S = 2 \times 0.9 \times (3.7 - 2) = 3kV$$

The first peak of TRV across the circuit breaker terminals is then

$$e_T = e + e_S = 32 + 3 = 35kV$$

The rate-of-rise of recovery voltage is

$$RRRV = \frac{e_T}{T_L} = \frac{35}{3.7} = 9.46kV/\mu s$$

Figure A.8 shows the time variations of the TRV and supply voltage obtained by calculation of transients in a 245 kV network with the same short-line fault conditions. These curves have been determined by a digital transient program. It can be verified the same values of peak TRV (e_T) and RRRV are obtained by the computer program and the simplified method of calculation.

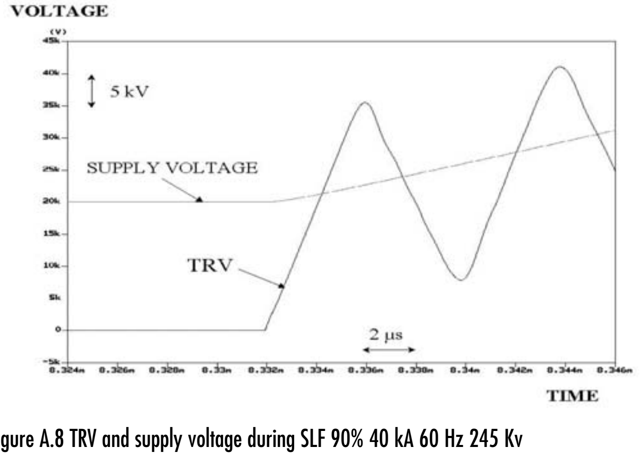


Figure A.8 TRV and supply voltage during SLF 90% 40 kA 60 Hz 245 Kv

Some engineers confuse the voltage peak that can be calculated from the peak factor defined in the standards, and the TRV peak (as shown in figure A.8) that is, by definition, the peak value of voltage seen across the circuit-breaker terminals. For this particular case, we have

- contribution of the line side voltage:

$e = 1.6 \times 0.1 \times \sqrt{2/3} \times 245 = 32kV$

with peak factor = 1.6 p.u.

- inherent TRV seen by the circuit breaker:

$e_T = e + e_S = 32 + 3 = 35kV$

- ratio of TRV to the crest value of the steady state voltage at the circuit breaker before interruption

$$\frac{35}{0.1 \times \sqrt{2/3} \times 245} = 1.75p.u.$$

The example A.5.3.3 shows that, in many cases, simple calculations, using the equations in this document, can be done to determine the main characteristics of a TRV, at least approximate values of parameters, and to check the validity of complex digital simulations.

Figure A.9 shows the TRV calculated by digital simulation in the case of a short-line fault at 75% of 40kA 60 Hz in a 245 kV network. Following the procedure presented previously, the reader is encouraged to calculate the peak value of TRV and the RRRV, and to validate his calculation with the curve shown in figure A.9 (peak TRV = 93.6 kV, RRRV = 8.4 kV/µs).

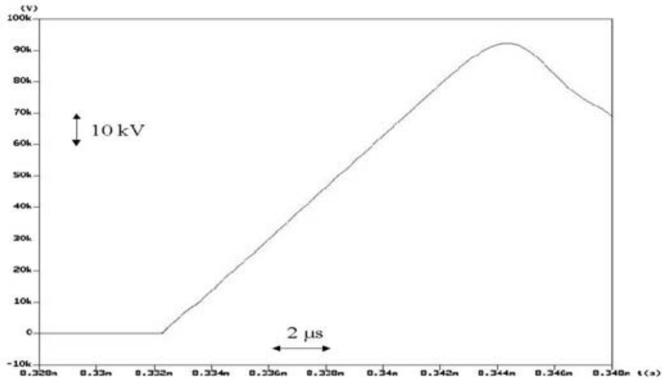


Figure A.9 TRV during SLF 75% 40 kA 60 Hz 245 Kv

A.6 EFFECT OF ASYMMETRY ON TRANSIENT RECOVERY VOLTAGE

The TRVs that occur when interrupting asymmetrical current values are generally less severe than when interrupting the related symmetrical current because the instantaneous value of the supply voltage at the time of interruption is less than the peak value (see Figure A.10).

When the circuit breaker interrupts, at current zero, the recovery voltage is lower than for the symmetrical case, due to the DC component of the asymmetrical current, as the TRV oscillates around a lower instantaneous power frequency voltage value.

Circuit breakers have the capability of interrupting these asymmetrical currents provided that they are applied within their rating.

Note: IEEE Std C37.081a-1997 gives the reduction factors of TRV peak and rate of rise of recovery voltage (RRRV) when interrupting asymmetrical currents.

A.7 EFFECT OF CIRCUIT BREAKER ON TRANSIENT RECOVERY VOLTAGE

The circuit TRV can be modified or changed by the circuit breaker's design or by the circuit breaker's action. Therefore, the transient recovery voltage measured across the terminals of two different types of circuit breakers under identical conditions can be different. Recognizing the modifying abilities of each of the various circuit breakers would be an immense task when either calculating a TRV or specifying a related value for the circuit breaker.

To simplify both rating and application, the power system electrical characteristics are defined or calculated ignoring the effect of the circuit breaker. Thus, the TRV, which results when an ideal circuit breaker interrupts, is used as the reference for both rating and application. This TRV is called the inherent TRV. An ideal circuit breaker has no modifying effects on the electrical characteristics of a system and, when conducting, its terminal impedance is zero; at current zero its terminal impedance changes from zero to infinity.

When a circuit breaker is fitted with voltage-distribution capacitors or with line-to-ground capacitors, these capacitors can reduce significantly the rate-of-rise of TRV during short-line faults.

Also, the remaining arc conductivity, which exists during a few microseconds after current zero, can reduce the RRRV. It is especially the case with circuit breakers with large blast pressures, such as air blast circuit breakers.

On the other hand, as has been explained in 7.3, current chopping can increase the load side voltage and the TRV in the case of shunt reactor switching.

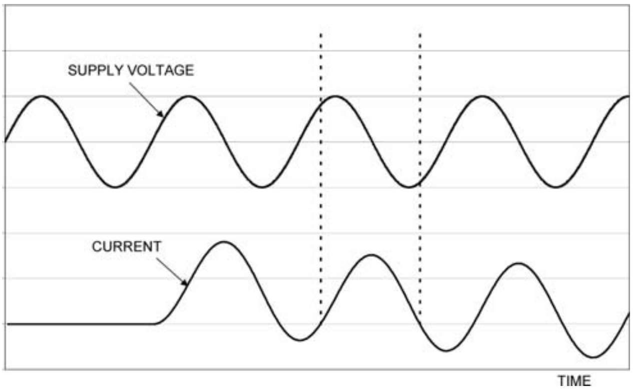


Figure A.10 Supply voltage and asymmetrical current

CORONA AND TRACKING CONDITIONS IN METAL-CLAD SWITCHGEAR CASE STUDIES

James Brady, Level-III Certified Thermographer, Brady Infrared Inspections, Inc.

INTRODUCTION

Electrical discharge in the form of corona and tracking has caused many failures in metal-clad switchgear with little advanced warning or understanding of the cause. This is especially frustrating for the end-user when infrared technology is being utilized as a predictive tool to prevent such occurrences. Because corona and tracking conditions are voltage problems that rarely produce heat, they go undetected during a typical infrared inspection. Fortunately, the combined use of ultrasound and infrared can enhance a switchgear inspection program by providing early detection of both heating and non-heating problems.

I was first introduced to ultrasound technology at an IR INFO conference. After realizing the applications and benefits of this predictive maintenance tool, we were soon offering this service as a routine part of our infrared inspection business. That decision has more than paid for itself by finding critical electrical problems for our clients that would have otherwise gone undetected using infrared alone.

This presentation will attempt to take the mystery out of the occurrence corona and tracking in metal-clad switchgear by discussing it s occurrence, what to look for during an inspection and case studies that have been documented over the past four years.

WHAT IS CORONA AND TRACKING?

Corona refers to the faint glow surrounding an electrical conductor of 3,500 volts or greater as a result of the ionization of air as the nitrogen in the air breaks down. When corona occurs, it creates ozone (detrimental to the human lungs, eyes, etc.), ultraviolet light, nitric acid, electromagnetic emissions and sound.

Ozone is a strong odorous gas that deteriorates rubber-based insulation. If moisture or high humidity conditions exist, nitric acids can also be formed that attack copper and other metals. The electromagnetic emission can be heard as interference on AM radios and the corona sound can be heard by the human ear and be ultrasonic scanning devices.

One important point to consider is that unlike infrared that detects heating due to current flow, corona indicates voltage problems and can be present without current flow. High potential in the electrical field is the major dictating factor for its presence. Corona activity is at its strongest on the positive (+) and negative (-) peaks of the 60Hz cycle.

Once corona becomes active, it leaves behind a conductive tracking path on surfaces and also creates a very conductive cloud of air around itself. A flashover can occur once a tracking pathway is completed from phase to phase or phase to ground (Figure-1). It can also occur from the conductive cloud of surrounding air once it finds a path to ground.

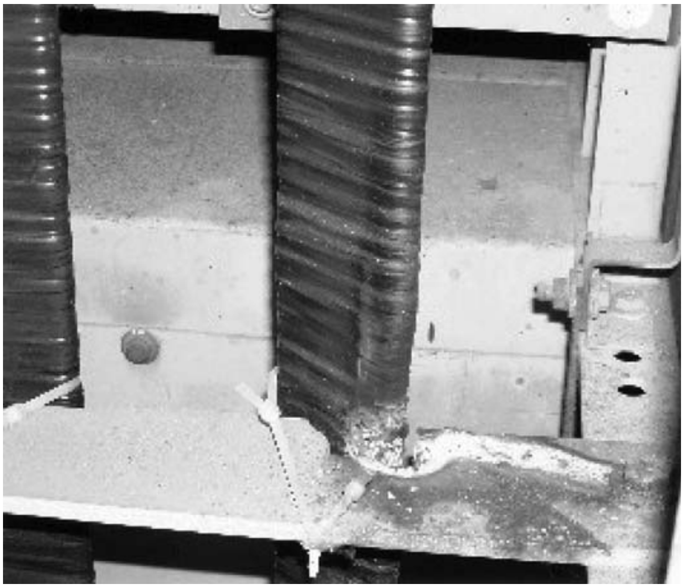


Figure-1: Advanced stage of carbon tracks on insulation board and insulated tape wrap on 4160V bus.

WHAT CAUSES CORONA?

Based upon numerous observed conditions of corona, there are three primary causes for its development; geometric factors, spatial factors, and contamination.

Geometric factors include sharp edges on conductors, connections and switchgear cabinet components. This may be the result of sharp or squared tape wraps in conductor terminations, tag ends on conductors, and corners and points on cabinet bracing and support shelves.

Spatial factors include small air gap spaces between conductors and other conductors, insulation board, and switchgear cabinet components. This may result from: 1) conductors being tie-wrapped together, 2) conductors touching insulators, conduit, and edges of cabinets, 3) non-shielded cables in contact with grounded surfaces, and 4) bus bars in close proximity to fiber-resin support and insulator material (Figure-2).

Finally, contamination in the forms of dust, oils/fluids, and other particulates on conductors and insulators will create corona (Figure-3). Corona conditions are exasperated by humid and wet conditions.

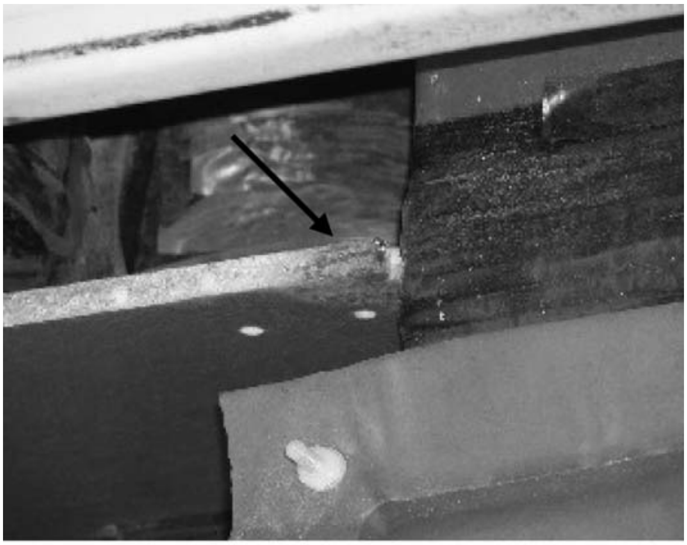


Figure-2: Caron tracks on insulation board close to 13kV bus bars.

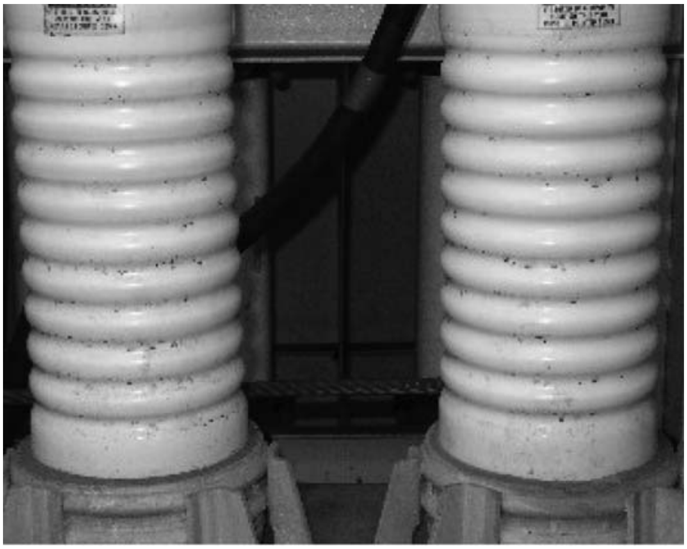


Figure-3: Contamination on ceramic bushing caused corona discharge to form.

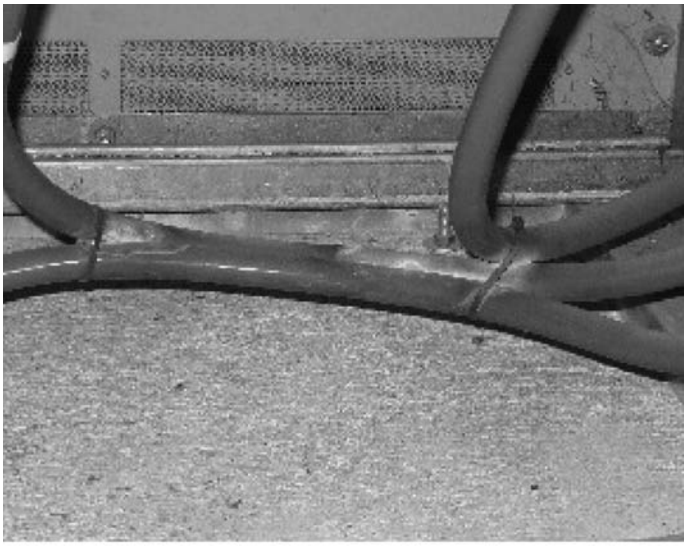


Figure-4: White powder/dust residue formed on 13kV power cables that are tie-wrapped together forming tight air spaces between each other.

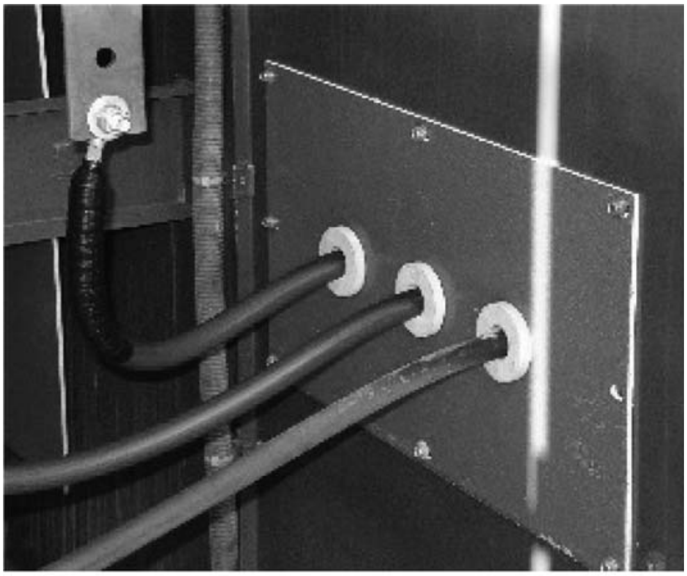


Figure-5: Non-shielded 23kV cables in contact with grounded porcelain collars produce corona conditions. Note discoloration of cable in foreground.

VISIBLE SIGNS OF CORONA AND TRACKING

Probably the most noticeable sign of corona will be the smell of ozone, since this is the major by-product of corona.

Early stages of corona may not show any visible signs. Mild cases of corona that are caused by metal edges in switchgear cabinets may never be detected by visual inspection alone.

Typically, the effects of corona on rubber-based insulators, tape, and insulation board will leave a white, fibrous power residue or dust (Figure-4). This dust is the physical breakdown of the material.

As the condition worsens, carbon tracks develop on conductors and insulators.

Depending upon the distance between the phase and ground will determine the time to a flashover.

Other indicators include discoloration and pitting on cable insulation (Figure 5).

Usually, dull finishes and micro-crack stains on cable insulation will be noticed. In worst-case scenarios, cables will be severely deteriorated (Figure-6).

Unusual weathering patterns on copper bus and conductors are also good indicators of corona (Figure-7). Humid and wet conditions inside switchgear cabinets will allow nitric acid to form, which attacks the copper surface leaving unusual weathering patterns. Cabinets lacking heaters, cabinets with poor weather seals, and those next to wet industrial processes are especially vulnerable to these conditions.

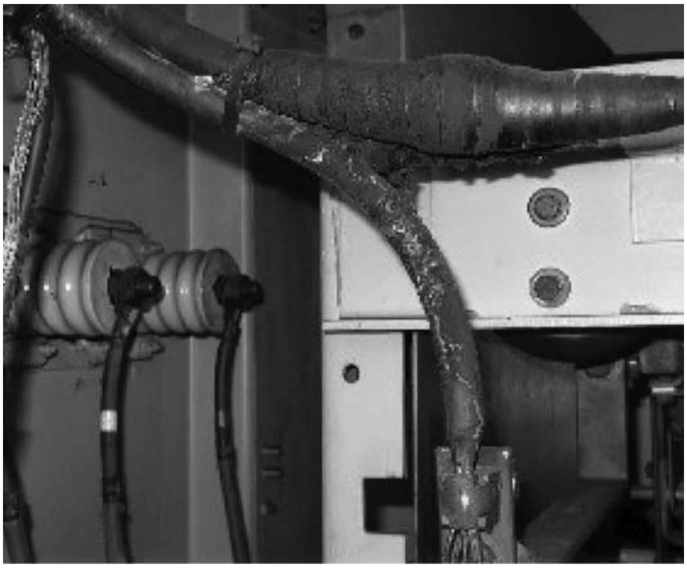


Figure-6: Severely deteriorated power feed cable in 4160V switchgear cabinet displaying white power and carbon tracks.

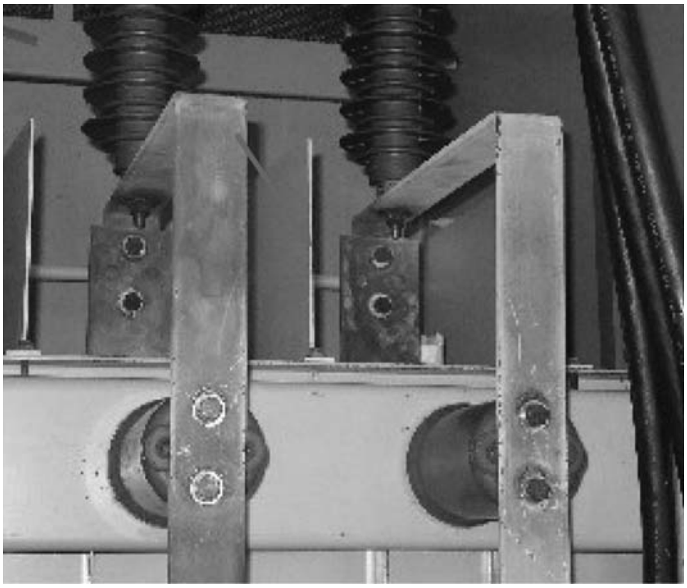


Figure-7: Unusual weathering pattern on 13kV copper bus under attack by corona produced nitric acid.

CORONA AND HEATING

Corona activity can produce a very faint heating pattern due to the molecular disturbance of electrons associated with the ionization of air (personal communication with Dan Ninedorf of Ox Creek Energy Associates Inc.). Depending upon air movement and the intensity of the corona, the delta temperature may or may not be detectable with infrared technology (Figure-8a & 8b). This can be deceiving for the infrared thermographer who is unfamiliar with corona, as this serious condition may only receive a minor severity rating if evaluated on temperature rise criteria alone.

Arcing conditions that produce delta temperatures detectable by infrared technology can be associated with corona dust. The conductive nature of the white powder left be by corona can support arcing conditions (See Case Study 4).

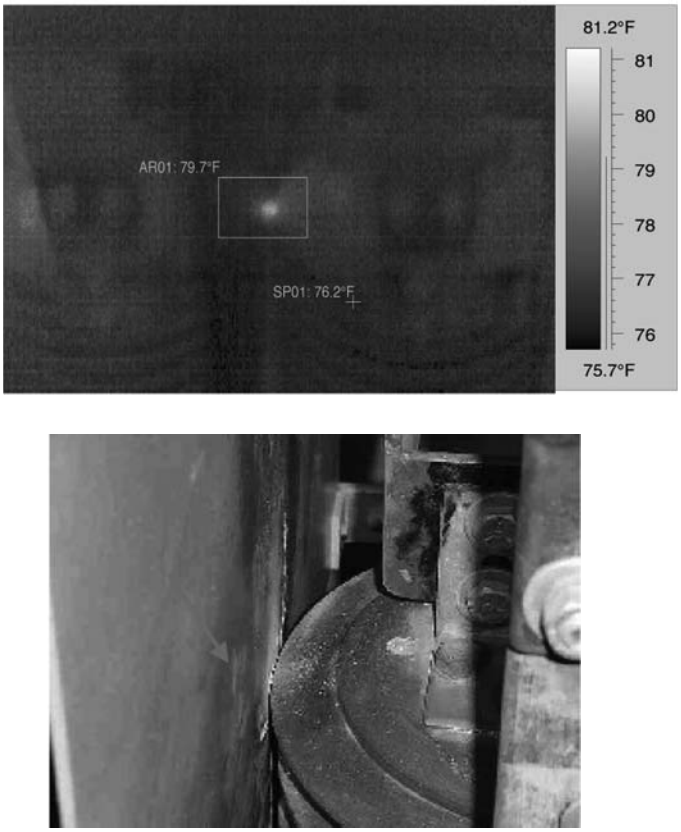


Figure-8a & 8b: A temperature rise of 3 F degrees observed on a 13kV bushing that has corona activity between itself and bakelite board insulation. (Note white powder on insulation board.)

ULTRASOUND TECHNOLOGY

Sounds above the normal range of human hearing (20 Hz to 20 kilo-Hertz [kHz]), are typically thought of as ultrasonic. A frequency range between 20 kHz to 40 kHz generally covers all of the ultrasonic applications used for predictive maintenance applications; leak detection, stream traps, bearings and lubrication, and electrical discharge.

The equipment includes a receiver unit, headphones, and various modular listening devices that attach to the receiver for both airborne and structure-borne scanning. Airborne devices include cone-shaped collectors that capture ultrasonic wave traveling through air. Structure-borne devices include magnetic base collectors and rod attachments used to contact the surface of equipment.

Through a process of heterodyning, the ultrasound signal is converted by the receiver unit to a low frequency audible signal that can be heard trough the headphones. There is also a read-out display that shows the intensity of the received signal.

USING ULTRASOUND TO DETECT CORONA AND TRACKING

Because corona and tracking problems are occurring in air, it makes sense that the best technique to detect these problems is through airborne ultrasound.

Ultrasonic waves are very directional in their movement, making it relatively easy to track problems back to their source. Because ultrasound waves are directional, they will rebound off surfaces and can be partially and completely blocked.

Using common sense and following the unit's strongest received signal will usually point the operator to the problem. The operator can also use blocking techniques to filter out competing ultrasound noises, if necessary.

Prior to opening a switchgear cabinet, it should be standard practice to scan ventilation screen openings, the seams around the doors, and the cabinet bolt holes once a few are removed. Typically, advanced cases of corona and tracking will be heard using this initial scan technique. However, the interior geometric design of the cabinet may not always allow the signal to reach the ultrasound collector or may only allow a partial and weak signal to be heard.

Likewise, mild cases of corona may have a very weak discharge signal that is not heard until the cabinet is open. If you have any question about the safety of opening a switchgear cabinet, do not open it until an outage can be secured.

Other problems that may affect the initial scan are competing ultrasonic noises generated by mechanical vibration from inside switchgear cabinets and hand tools used to open the cabinets. Mechanical vibration signals can sound a lot like electrical discharge signals. By applying light pressure on the sides of cabinets and doors, you can reduce or eliminate a mechanical signal and rule it out as electrical discharge.

Opening switchgear cabinets is a risky business that should only be performed by qualified persons wearing the appropriate arc-flash protection equipment as prescribed by the NFPA 70-E guidelines. If at all possible, cabinets should be open while de-energized, and then energized for the inspection. If a strong smell of ozone is detected, do not open the cabinet until it is de-energized. Drafting air into a cabinet with advanced corona and tracking conditions may move conductive air over a grounded object and cause a flashover.

Teamwork between qualified persons is a must. If you are an in-house technician with high-voltage switchgear, consider installing hinges on doors and modifying bolts that can be easily handled while wearing gloves. Doors should be opened very slowly. You should minimize your exposure in front of the open equipment.

Once open, the inspector should slowly scan the interior of the cabinet making sure to cover the entire area. Both front and back compartments should be scanned, if accessible. Never should the ultrasound instrument or any body parts break the plane of the cabinet or exceed the approach distance for the given voltage class.

WHAT ARE WE LISTENING FOR?

Corona problems will be heard as a continuous buzzing or frying noise. The intensity of this noise will be directly related to the severity of the problem.

Tracking problems will sound much like corona problems but will have pauses and possible drops and builds in intensity.

Once a problem is detected, the problem should be described, photographed, and recorded. Because of the dangers involved with getting too close to this type of equipment, using a telephoto lens will help become your eyes to get close to problem. Also, a bright flashlight will help illuminate dark and tight areas where corona problems may occur.

CORRECTIVE ACTION

You just received word that corona is present in your switchgear. How bad is it? What corrective action should you take?

The presence of corona and/or tracking in switchgear is a serious problem that should be addressed as soon as possible. The following corrective actions have been suggested by Mark Lautenschlager, PE and Senior Vice-President of Engineering with High Voltage Maintenance Corporation:

- Any physical sign of breakdown or injury to conductors, insulators and insulation board should be corrected by repairing or replacing the damaged component.
- Fill air gas with silicon tape, silicon sealant or other corona suppressive compound. Air gaps can also be increased or replaced with porcelain insulators.
- Smooth sharp edges, apply corona rings, apply semi-conductive tape or compound or wrap edges with metallic screening to form round conductive surfaces.
- Replace damaged terminations and splices on conductors. Support nonshielded cables from ground.

CONCLUSION

Unlike resistance problems associated with current flow that can be detected by infrared, corona is a voltage problem that seldom generates heat. Corona and tracking problems can be easily missed by infrared and remain enigmatic until a major fault occurs that destroys switchgear equipment. The use of ultrasound technology compliments an infrared inspection program by increasing one's ability to locate these destructive problems and take corrective action.

In most cases, corona and tracking problems provide visual evidence of their existence. Understanding the factors that cause these problems and their physical clues should bring a new awareness to the infrared thermographer.

CASE STUDIES

Four case studies are presented here that provide a cross section of various problems and conditions associated with corona and tracking problems in metal-clad switchgear.

Case #1: Tracking Inside 13kV Rack-in Breaker Cabinet

Background: During a recent inspection at a substation for a utilities provider, a series of 13kV rack-in breaker cabinets were being scanned with infrared and ultrasound. One of the rack-in breakers was completely removed from the main bus cabinet following a recent flashover.

Because of the no load conditions inside the cabinet, infrared was ineffective. However, tracking discharge was easily picked up by the ultrasound scanner.

Comments: The most logical explanation for the tracking condition is the problem that caused the initial flashover is still present. The presence of carbon-rich flash residue will only exasperate the situation by providing very conductive material for tracking paths.

Avoided Cost: Prevented the potential loss of a main bus responsible for five feeder breakers at a downtown substation.

CASE STUDY 1

Priority 1 – Take Out of Service

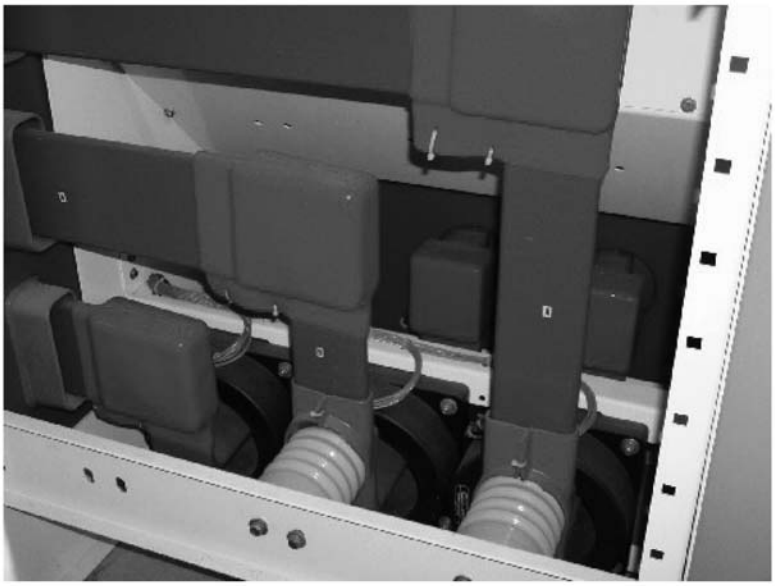
LOCATION: Substation-5

EQUIPMENT I.D. Breaker Cabinet 13-05-06

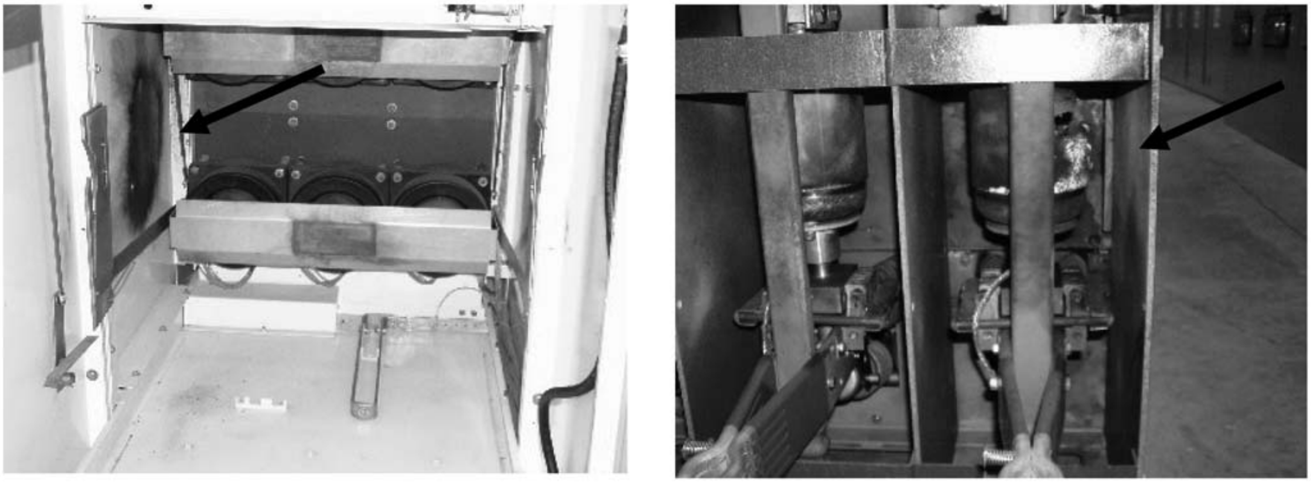
SPECIFIC ITEM: B- phase stationary contacts

DESCRIPTION OF PROBLEM: Tracking detected on contacts carbon present from recent failure No load on equipment during survey

Case Study 1



Back side of cabinet showing stationary contacts



Front side of cabinet with carbon residue and electrical flash-over on breaker

Case #2: Tracking Inside 13kV Load Interrupter Switch

Background: During an inspection last year at a citrus industry, the outside ventilation screen on a 13kV load interrupter switch cabinet was scanned using ultrasound. The switch was tied to a step-down transformer which, in turn, was tied to 480V switchgear, of which the main breaker was open. Because of this, it was determined that the 13kV switch was under very light load.

Ultrasound detected a very strong signal characteristic of tracking conditions. The 13kV switch was de-energized and opened for visual inspection. Carbon tracks were discovered on the insulation board separating the B- and C-phase fuses.

Comments: Fortunately, this condition was found just in time. This switch was scheduled to be brought on-line with load shortly after the inspection and would have undoubtedly failed soon thereafter. Maintenance personnel replaced fuses, cleaned all metal parts and installed new insulation board. Once repairs were complete, the switch was energized and a follow-up ultrasound scan was performed confirming repairs were successful. The switch was then brought on-line with load and ultrasound and infrared were performed, again confirming that repairs were successful.

Avoided Cost: Prevented the potential catastrophic loss of a 13kV load interrupter switch responsible for over 20 million gallons of citrus product storage.

CASE STUDY 2

Priority 1 – Take Out of Service

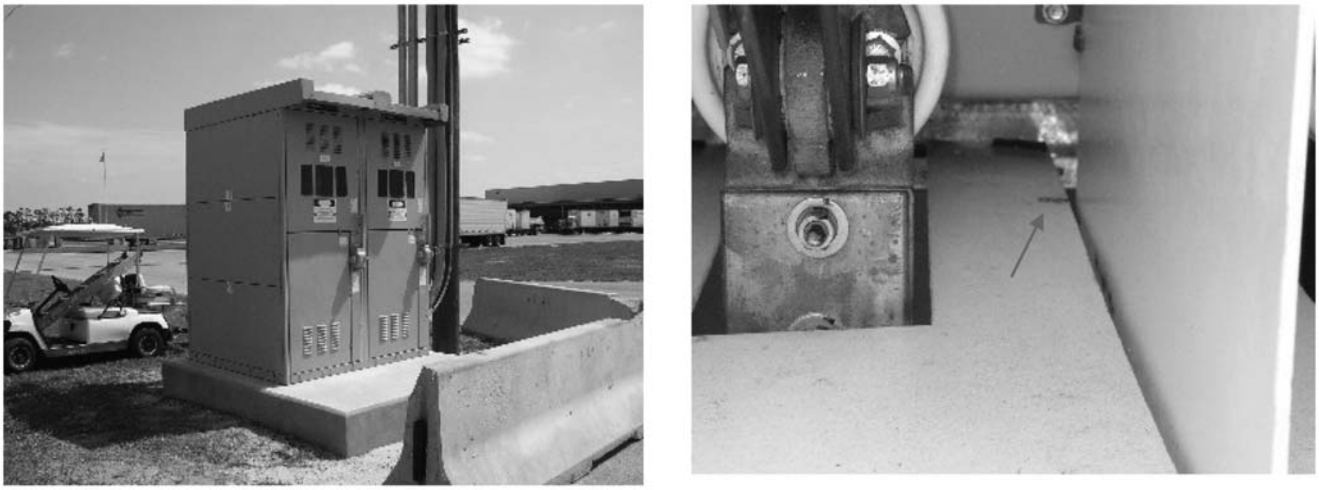
LOCATION: Substation 17

EQUIPMENT I.D. Substation 17- Feed to ATF XFMR

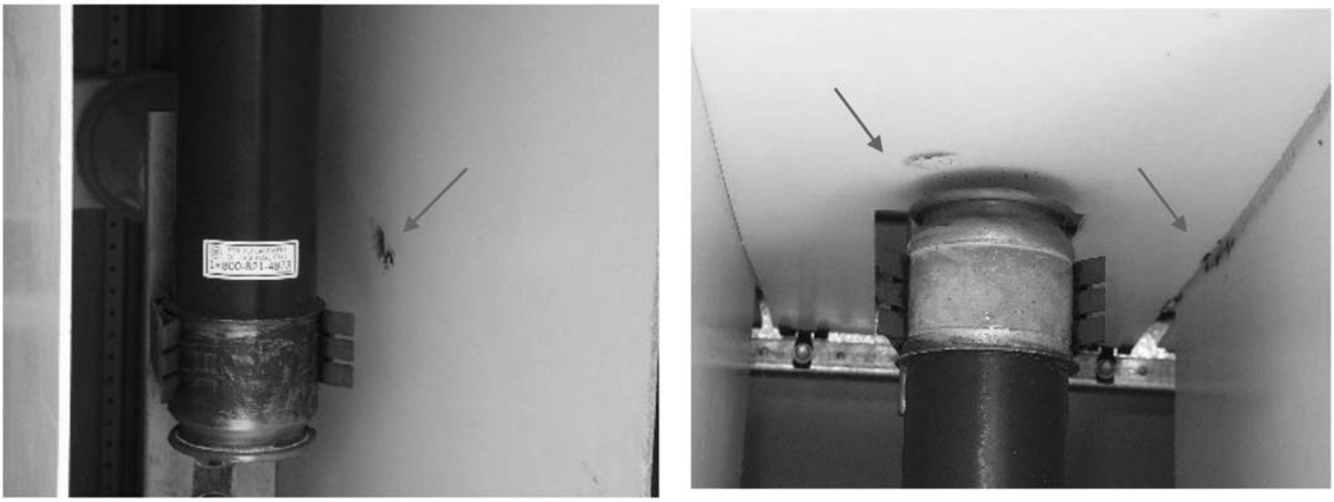
SPECIFIC ITEM: 13kV Load Interrupter Switch

DESCRIPTION OF PROBLEM: Tracking conditions detected - No load on equipment during survey

Case Study 2



13kV Load Interrupter Cabinet / Carbon tracks on B-phase insulation



Carbon tracks on insulation between B- & C-phase fuse

Case #3: Corona inside 13kV Transformer Cable Compartment

Background: During an inspection last year at a citrus industry, a pad-mount step-down transformer cabinet was scanned with infrared and ultrasound. Infrared results showed all connections and conductors to be normal. Ultrasound found advanced stages of corona on the 13kV power feed cables entering the transformer cabinet through a 3-inch galvanized conduit.

Comments: A visual sign of the corona was white residue powder in the small air gap spaces between the cables and the conduit.

Avoided Cost: Prevented the potential catastrophic loss of a pad mount transformer and adjacent 13kV load interrupter switch responsible for the plant's feed mill operations. All of the others plant's operations are dictated by the operation of the feed mill.

CASE STUDY 3

Priority 2 – Correct ASAP

LOCATION: Substation 14

EQUIPMENT I.D. 13kV / 480V Transformer

SPECIFIC ITEM: INCOMMING POWER FEED Cables

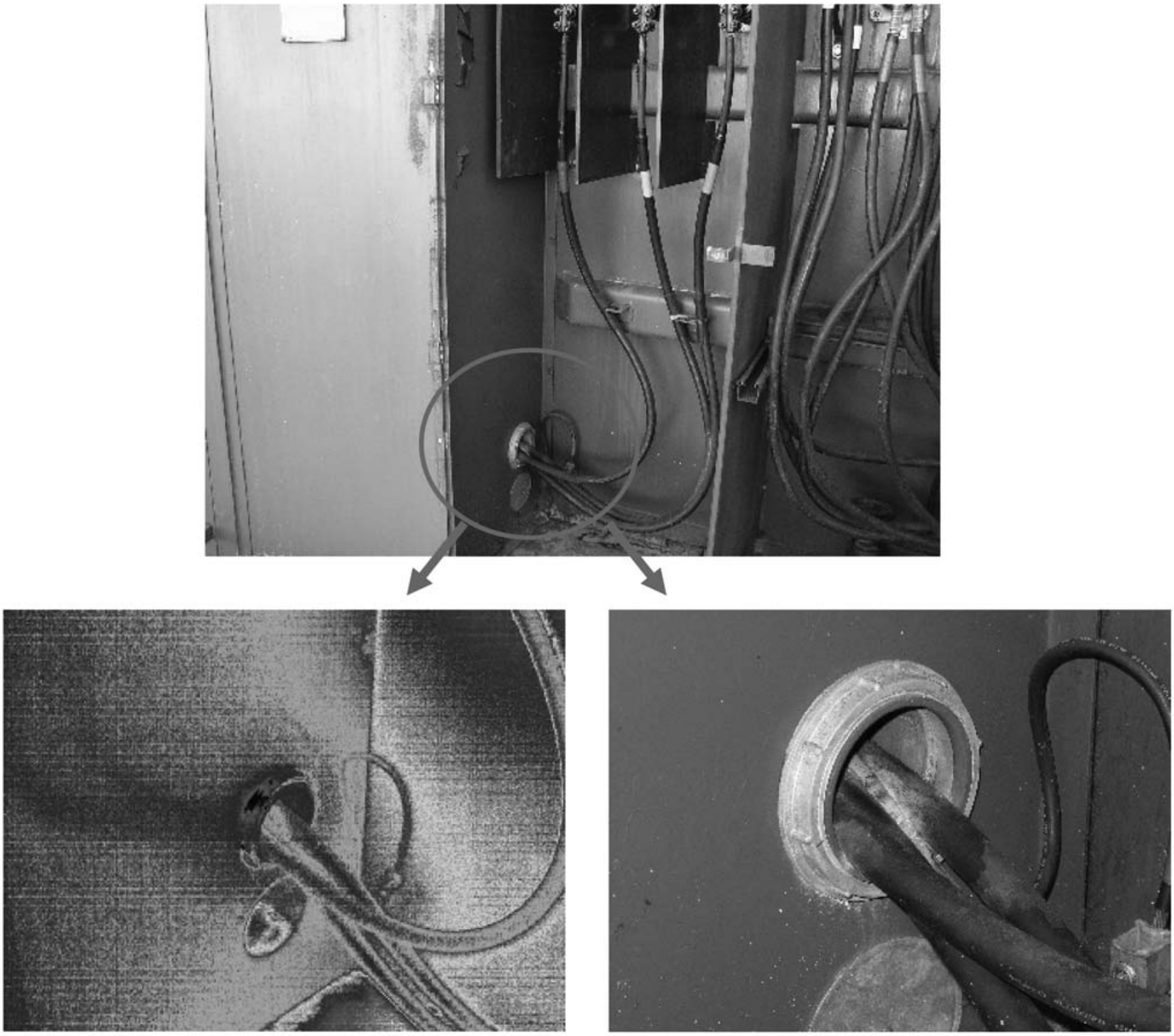
DESCRIPTION OF PROBLEM: Ultrasound detected presence of corona on feed lines. Non-shielded cable in contact with ground

Case #4: Corona and arcing on 23kV Ceramic Bushing

Background: During an inspection two years ago at a telecommunications provider for South America, the 23kV main switchgear cabinet for the facility was inspected with infrared and ultrasound.

Infrared results showed a small hot spot on one of the ceramic support bushings for the B-phase bus. Ultrasound found advanced stages of corona at the same location.

Case Study 3



IR image shows no thermal anomaly - Dust / residue on cables from breakdown of insulation

Comments: A visual sign of the corona was white residue powder at the same location of the hot spot. Communication with Dan Ninedorf of Ox Creek Energy Associates Inc. about this unusual hot spot revealed that arcing conditions can be supported within the white powder dust of corona.

Avoided Cost: Prevented the potential catastrophic loss of the main switchgear responsible for the facility's operations.

CASE STUDY 4

Priority 2 – Correct ASAP

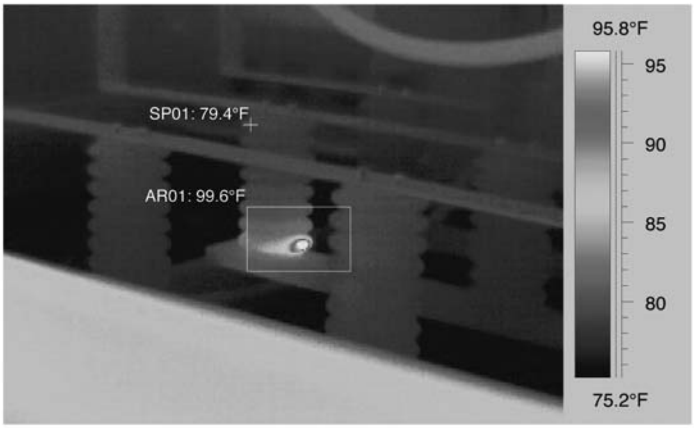
LOCATION: Outside Substation Area

EQUIPMENT I.D. Substation TB - Load Interrupter Cabinet 23kV

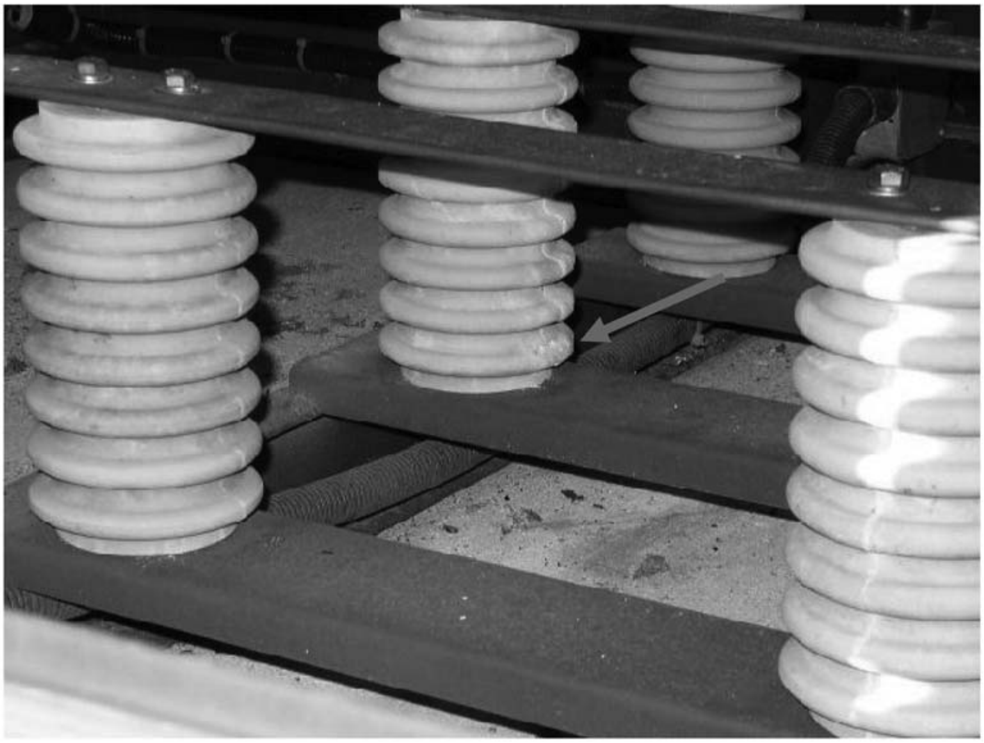
SPECIFIC ITEM: Ceramic Stand-off bushing

DESCRIPTION OF PROBLEM: Sustained arcing within corona powder on bushing.

Case Study 4



Delta T of 20 F degree on bushing hot spot



Conductive corona powder / dust on bushing supporting arcing conditions

IMPORTANT MEASUREMENTS THAT SUPPORT INFRARED SURVEYS IN SUBSTATIONS

Robert Madding and Gary L. Orlove, Infrared Training Center, FLIR Systems,

Ken Leonard, Carolina Power & Light

ABSTRACT

You have found a hot spot in a substation with your Infrared (IR) camera, also known as a thermal imager. You know it is a problem, and you must now determine just how bad it is. Does it need to be fixed immediately, or can it wait a few days, a few weeks? What other useful information could you measure while in the substation? Two very important measurements are load and wind speed. Both strongly affect the apparent severity of a problem. In a ring-bus, or parallel bus system, knowing the current in each side is crucial to making the proper call. This paper discusses making these measurements safely, using inexpensive instrumentation that is currently available.

1. INTRODUCTION

Substation IR surveys are an efficient means of identifying problems under energized operating conditions. There are hundreds to thousands of connections in a substation, depending on its size. Making individual measurements on each one would be prohibitively time-consuming. Modern infrared cameras, also referred to as thermal imagers, do a great job of spotting problems when in the hands of the well-trained thermographer, one who understands direct and indirect measurement, emissivity, distance, load, environmental and other parameters that impact what the thermographer sees through the eyes of the IR camera or thermal imager. But not every problem needs fixing right away. Some can wait; others cannot. After acquiring good IR data and finding problems, their severity is the greatest challenge facing the thermographer.

Experience goes a long way in the problem severity arena. But measurements that support the thermal imager data can be very useful in assessing how bad the problem is. Load is crucial. A 45 F temperature rise, direct reading, under 50% load is a much more severe problem than the same temperature rise under 90% load. This temperature rise measured in a 10 mph wind is much more severe than in no wind. Both wind and load effects are discussed in detail in other publications (1,2, 3). Other environmental parameters such as solar load, air temperature and humidity play lesser, but still important roles.

2. SAFETY CONSIDERATIONS

People who walk in the woods have no idea of the power stored in the mass of a tree. A lumberjack felling such a tree gets a real hint when the tree hits the ground, the earth shakes and a large, long dent is left behind. One who cuts this tree into smaller sections for firewood and carries them out by hand gets a real feeling for the tremendous mass of even a fairly small tree. They look harmless, just standing there. But if one falls on you, you're dead.

Electric power also appears harmless. It's not snarling, roaring or hissing, all prehistoric danger signals we humans have learned to recognize for our survival. Electricity is just there, not obviously dangerous. We must learn through training how to stay alive in this seemingly benign, but potentially deadly environment. High voltage is unforgiving. You don't get second chances.

For substation work, never enter a substation without being accompanied by qualified personnel. Always have a tailgate meeting before starting your IR survey. Learn and follow their rules. Discuss their problem severity criteria. Wear proper safety equipment. Hard hat and safety glasses are universal. Some utilities require long sleeve cotton shirts and leather shoes. Others may only require short sleeves. Find out clothing requirements before you go there.

Use your senses to get a first reading on the health of the substation. Sniff for oil, listen for arcing, look for obvious problems, such as a wire on the fence. Use your IR camera, also known as a thermal imager to get an initial overview of the substation. Do a quick look for major problems. If you find a critical problem, you may need to "freeze and leave". That is, freeze and save the image, then leave the area to a safe location. The substation electrician or qualified host will want to contact the proper personnel to take action on such a critical problem. What you do not want to do is ask everyone to "come and look at this thing that is about to blow up!"

Usually, you don't want to extend anything above your head. We often do this to measure wind speed as the wind speed can be different at the target. Get permission from the substation qualified person as to where you may perform such activities. Let the qualified person open control cabinets and operate any controls or buttons. (Often, loads can be read out digitally if you know how to access the data.)

Figure 1. Kestrel 3000 pocket weather meter.

Learn how to do IR surveys in substations. This paper is an adjunct to basic substation IR survey training. You should be able to identify the components, have a basic understanding of their function and purpose, know what to look for, know where the indirect measurements are, have a fundamental understanding of equipment criticality, and know a dangerous situation when you see it.

3. MEASURING AND CORRECTING FOR WIND SPEED

The Kestrel 3000 wind meter, Figure 1, is used by many thermographers to get wind speed, air temperature, and relative humidity. It also gives dew point temperature, wind chill and heat index. It is a pocket size instrument and sells for about $150. Wind speed can dramatically affect hot spot temperature and associated temperature rise. A 3 mph wind can cut the temperature rise in half from no wind conditions! A simple wind speed correction factor doesn't exist as the correction depends on the watt loss of the hot spot. Correcting for wind speed on "direct" targets can be done using Figure 2, taken from reference 1. To do this accurately, you would multiply the resistance of the directly read hot spot by load in amps squared to get the watts of power (I2R) being dissipated as heat. Figure 2 gives three power values, 7.9, 18 and 27 watts. You could roughly interpolate between these values. For example, for a resistance of 250 micro- ohms, 230 amp load, the power loss is 13.2 watts. For a 10 mph wind, the correction is about 3.5. You could multiply the measured temperature rise by this value to get the corrected value.

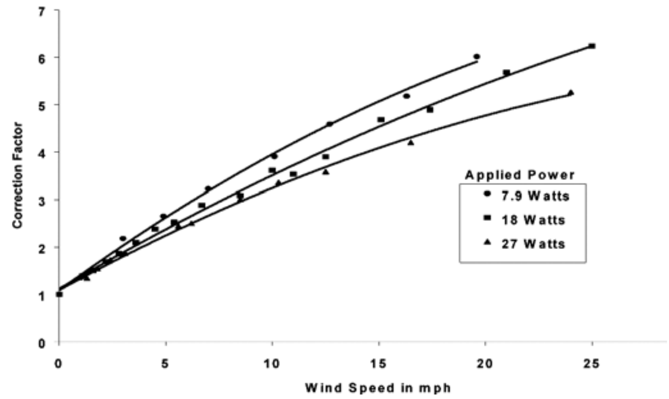


Figure 2. Wind speed correction factor vs. wind speed for various power levels. From reference 1.

The following considerations are why it is difficult to get accurate temperature rise corrections under windy conditions:

- Considering the uncertainties in emissivity and background, your initial temperature estimates can have fairly wide error bars. Does it make sense to go to a lot of work to accurately correct an already uncertain measurement?
- Load and wind speed are related. The correction depends on load. Do you correct for existing load, or do you correct for maximum load?
- Knowing the wind speed at the component is also problematic. The Kestrel does a great job of measuring at its location. But the wind can vary significantly from that point to the part in question.
- What wind speed value do you correct to? You need to correct to the minimum wind speed expected under load conditions, not necessarily zero wind speed. If the wind is always blowing, and there are areas where this is the general case, what is the lowest value?
- Getting the connection resistance is problematic. And once you know the connection resistance, you already have enough information to make a call on severity.

Our heads were spinning when we realized all the drawbacks to wind speed correction. Trying to get accurate wind correction on these measurements doesn't necessarily make a lot of sense. But multiplication factors of 3 or 4 are not small corrections and need to be recognized at some level. Familiarize yourself with the chart. Get some idea of the minimum wind speed in your area. Recognize that wind can play a major role in cooling a component. Try to get measurements under minimum wind conditions. Avoid doing thermography in high wind conditions.

Should you estimate a wind speed correction every time? No. If the temperature rise is already fairly high, and the load is nominal, you know that at full load and no wind, the temperature rise will be significantly higher. Or, if the temperature rise is already at the critical level, the correction cannot push it to a higher level.

Wind speed correction is useful for those nominal temperature rises, like 30º F. This doesn't sound too bad for a direct measurement. But, if measured in a 10 mph wind, the corrected value ranges from about 90º to 120º F, if you are correcting to zero wind speed. It is often very important to make a wind speed correction estimate.

4. LOAD MEASUREMENT

Load (current) is very important for the thermographer. Heat is generated in a bad connection by electric current flowing through a resistance. The power loss can be calculated as shown above. It is directly proportional to the square of the load. But temperature rise is not directly proportional to the square of the load. It follows a more complex pattern as discussed below.

However, if you don't know the load, you can be completely in the dark about problem severity. Again, if you find a very high temperature rise, one that exceeds the critical or upper limit of your severity criteria, you don't need to know the load. For problems that uncorrected are not critical, knowledge of the load is crucial. You need to know both the actual load and the maximum load to do a proper evaluation.

For a ring bus problem, measuring the load can save someone's life. Unfortunately (or fortunately for the utility), we did not find a ring bus problem to give as an example in this

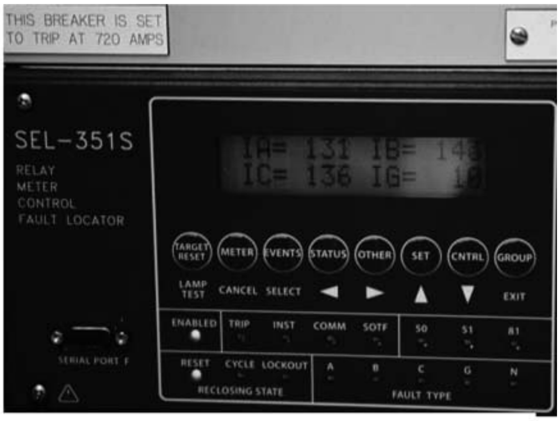


Figure 3. LCD readout of amperage on an OCB control panel.

paper. Earlier work (4) prior to our ability to measure the load directly in the switchyard, gave an example where 1200 amps entered the ring bus, and by calculation we determined 1050 amps flowed through one leg and only 150 amps flowed through the other. If the operators did not know this, they could well open the "good" side and attempt to force all 1200 amps down the "bad" side. The measured resistance of the bad connection that shunted most of the current down the other side was 96,000 micro-ohms.

Opening the good side would cause 1,200 x 1,200 x 0.096 = 138,240 watts to be dissipated in the bad connection. The result would have been catastrophic. We recommend never opening one leg of a ring bus when you know you have problems, without first measuring load in both sides of the bus.

How do you get load in a substation? Often, control cabinets have a readout that gives the current for each phase. Figure 3 gives an example. Or, you may be able to contact the control room and get a load reading from them. Basic electricity says that all the current that flows into a wire flows out of the wire, so this value is valid as long as the conductor doesn't split, as in the ring bus example above. When this happens, you cannot assume a 50/50 split in the current flow. It depends on the resistances in each side of the parallel circuit.

For these cases and when no readout is available, you can make your own measurement with a portable ammeter on the end of a hot stick. We used the Ampstik shown in Figure 4. The ammeter attaches to the end of a telescoping hot stick. The reading is stored and read out when retrieved. Newer models will store several readings so you don't have to retrieve the meter each time. Figure 4 shows a typical measurement. Proper training is required for measuring high voltage live line current. Only qualified personnel should do this!

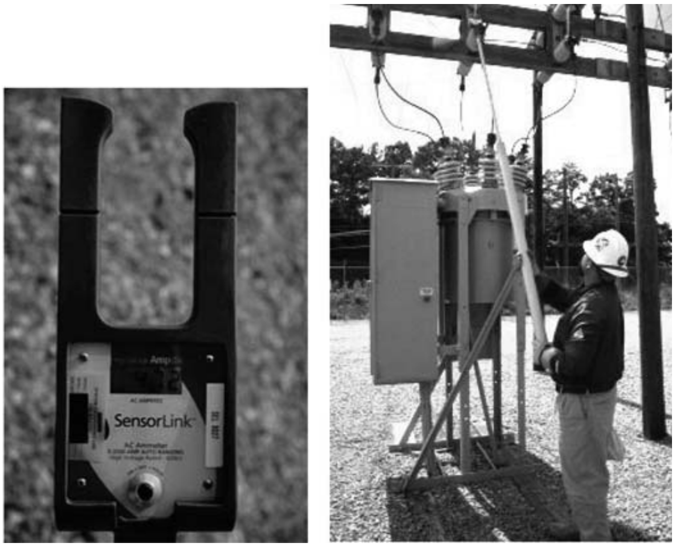


Figure 4. Close-up of the Ampstik and in use to measure one side of a switch.

Figure 5 is the IR image of the B-phase and C-phase of a 23 KV line side disconnect. The switches have an inverted Y configuration, so there is a parallel path between the hinge and the jaws. In both cases the left side hinge is hot while the right side is cool. We measured the current through each side of each phase and found almost all the current was flowing through the left side of both the B- and C-phase switches. We interpret this as both sides of the hinge are bad on both switches. The right side is much worse than the left side, forcing most of the current through the left side. We also found the current beginning to become imbalanced in the A-phase switch which may indicate an impending problem. We recommended all three switches be repaired or replaced.

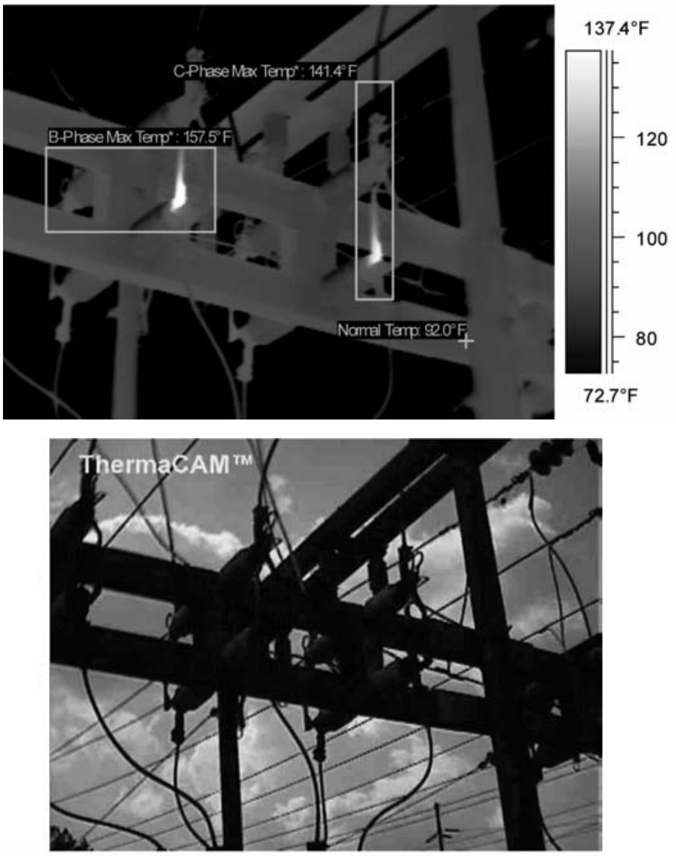


Figure 5. Thermogram/photo pair showing problem line side 23 KV OCB switch disconnects on B- and C-phases.

Once you have determined the load, you need to find what percentage of maximum load it represents. To do this, divide the measured load by the maximum load and multiply by 100 to get a percentage.

In this case, we must consider two maximum loads. One is a "normal" maximum that can occur daily during hot weather. The other is a "two feeder" maximum where due to other problems two OCBs are fed through these switches. In the following section, we will use this as an example for load correction of temperature rise.

5. LOAD CORRECTION

There have been many attempts to derive a simple load correction factor where the temperature rise for a known load is multiplied by a number to give the full load temperature rise. In this way, the severity of the problem can be evaluated for full load conditions. Or, one could calculate the load that would give the maximum temperature rise for safe operation.

The power dissipated as heat equals the square of the load times the electrical resistance (P=I2R). One might then expect the temperature rise to vary as the square of the load. If the load doubled, the power dissipated increased by a factor of 4, and the temperature rise increased likewise. For heat transfer by conduction alone, this is valid. But heat transfer by radiation depends on temperature to the fourth power (T4 Stefan

23 KV Oil Circuit Breaker Line Side Switches					
Phase	Left Side Amps	Right Side Amps	Total Amps	% Load Normal Max 275 Amps	% Load Two Feeder Max 525 Amps
A	69.8	129.5	199.3	72%	38%
B	195	1.8	196.8	72%	37%
C	193	2.0	195	71%	37%

Table 1. Measured current on inverted Y switches, each leg and total.

Boltzmann Law). Convection as well is dependent directly on temperature rise only in limited regions. Both play an important role in electrical problem heat dissipation. The square assumption predicts a much too high rise, and should not be used (2, 3).

One might assume the temperature rise (DT) increases as some power of the current and so attempt to fit DT=InR, where the current is raised to the nth power, n being determined by fitting data or modeling. Perch-Nielsen et al (3) did some experiments and found n varied between 0.6 and 2 depending on conditions.

We used the power loss software (5) to calculate the effects of changing load for various emissivity targets, air temperatures and background temperatures. We fit the resulting data to the above equation to find n for various conditions. Our modeling shows there is no single value for n for all cases. There is no simple load correction factor. We found a range of exponents (n-values) from a high of 1.6 to a low of 1.46. Our modeling considered a low emissivity target (minimum of 0.6) to a high emissivity target (maximum of 0.95) with an air temperature of about 70 F and background temperature ranging from 70 F to -13 F. The simulated target was 4” wide by 1” thick by 6” tall. The value of n decreases as heat transfer by radiation increases due to its non-linear, T4, nature. Strongest radiation occurs for high emissivity, low background targets.

Figure 6 shows our modeled estimates for limiting conditions that will give the thermographer a reasonable idea of the multiplication factor to use for full load correction (values of n are given in the legend). These are “middle-of-the-road” results compared to others referenced above. But they do represent the bounds of what we found with our modeling. The factors are not small, and like the wind correction, can make a huge difference in your severity estimates. Figure 6 also shows that performing IR surveys under low load conditions leads to greater uncertainties in predicting the temperature rise at full load conditions.

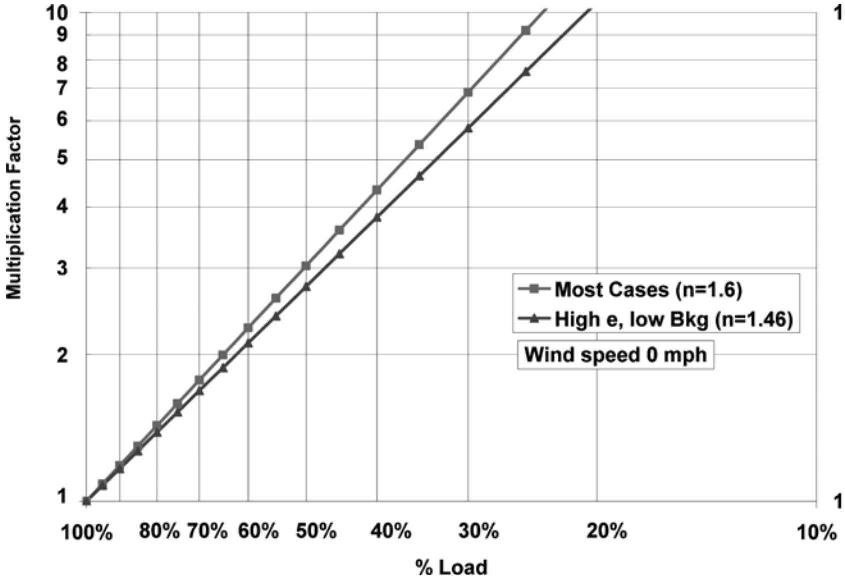


Figure 6. Load Correction. Multiply temperature rise by factor given at measured % load to correct to full load conditions.

As the graph is in log-log format, it is a bit tricky to estimate the values between gridlines. For those mathematically inclined, you can calculate the value as follows: Multiplier = (1/%load)n. For example, at 50% load, the maximum correction (n=1.6) would be (1/0.5)1.6= 21.6=3.03. Many calculators have the yx function to do this type of calculation. But as these are estimates, it is simpler to look at the chart and estimate the value.

Let’s use the load correction chart to estimate the temperature rise of the hot switch components shown in Figure 5. The B-phase shows a 65.5 F rise, the C-phase a 39.4 F rise. Wind speed was 0 mph. For the normal full load condition, the load is about 70%. The correction factor read from Figure 7 is about 1?, so the normal full load corrected temperature rises would be about 115 F and 69 F, respectively. For the two-feeder full load condition, load is about 40% and correction factors range from about 33/4 to 4?. Corrected temperature rises are then about 245 to 278 F for the B-phase and 148 F to 167 F for the C-phase. Table 2 summarizes our estimates.

These corrected temperature rises give the thermographer excellent information about what to expect when the load goes up. They can be used to help evaluate risk of going to higher loads.

So, even though we still don’t have the complete story on load correction, we strongly recommend thermographers consider the range of values for temperature rise that could be realized as the load increases. The load correction curves are for zero wind conditions. Trying to correct both for wind and load can be problematic as they are related. We recommend not performing IR surveys in low load, windy conditions. You will miss some problems, and correcting for those you do find can be difficult. If you must go out in those conditions, plan to return as soon as the wind goes down and/or the load goes up.

6. SUMMARY

Wind speed and load are two important measurements in addition to your IR camera or thermal imager data when working on electri-

% Load	B-Phase Initial Rise in F	C-Phase Initial Rise in F	B-Phase Corrected Rise in F	C-Phase Corrected Rise in F
70% (Normal)	65.5	39.4	115	69
40% (Two Feeder)	65.5	39.4	245-278	148-167

Table 2. Raw and full-load corrected temperature rises.

cal systems. Though written with substations in mind, the work is equally valid for other areas such as distribution and transmission lines.

Measuring wind speed and load in a substation is a lot easier than correcting temperature rise data for them. This paper shows the correction factors in both cases are large, so even though we do not have all the answers at this point, the wise thermographer will do well to consider their significance. Further research and experimentation need to be done to help quantify these factors and provide thermographers with even better correction tools. Be very wary of simple wind or load correction factors. They don't exist at this time.

For a ring bus, or parallel circuits, problems found with IR should be backed up with load measurements of each parallel leg. It can occur that a major problem is shunting so much current it appears cool whilst a smaller problem in the other leg shows hot due to the high load it is carrying from the shunted current. Safe practice says measure the load and be sure. The switch example illustrates this, though safety was not an issue in this regard as both legs of the switch would open at the same time.

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8. ACKNOWLEDGEMENTS

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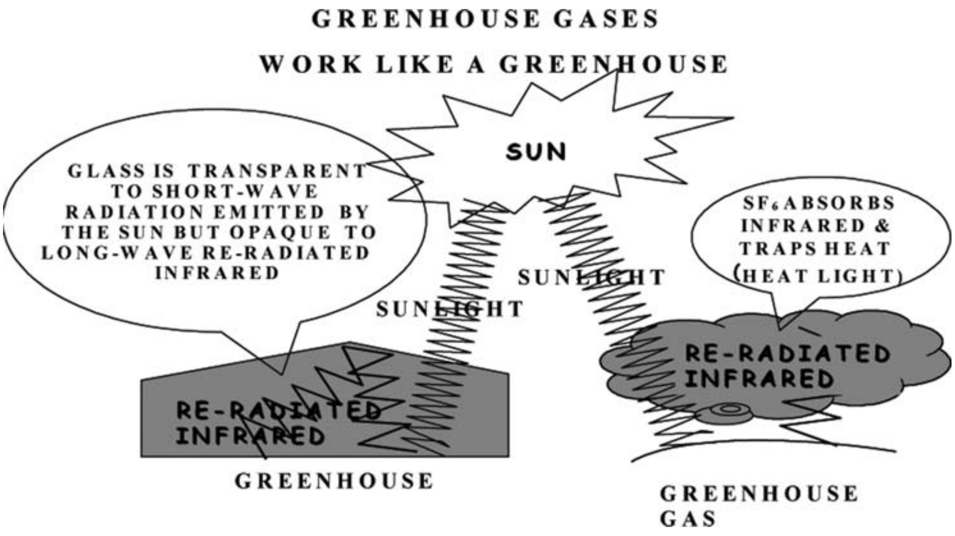
EXPERIENCE WITH INFRARED LEAK DETECTION ON FPL SWITCHGEAR

Dave Keith, Field Service Manager, Roberts Transformer; John Fischer, Project Manager, FP&L;
Tom McRae, President, Laser Imaging Systems


GREENHOUSE GASES
WORK LIKE A GREENHOUSE
SUN
GLASS IS TRANSPARENT TO SHORT-WAVE RADIATION EMITTED BY THE SUN BUT OPAQUE TO LONG-WAVE RE-RADIATED INFRARED
SF₆ ABSORBS INFRARED & TRAPS HEAT (HEAT LIGHT)
SUNLIGHT
SUNLIGHT
RE-RADIATED INFRARED
RE-RADIATED INFRARED
GREENHOUSE
GREENHOUSE GAS

INTRODUCTION:

Sulfur hexafluoride (SF6) is an excellent dielectric gas that is used extensively in high-voltage power equipment. It is chemically inert, non-flammable, non-toxic, and non-corrosive under normal conditions. The power industry is a major user of this gas.

ENVIRONMENTAL:

Studies have found SF6 23,900 times more effective at trapping infrared radiation than CO2.

Its atmospheric lifetime is estimated at 3,200 years. At the 1997 Kyoto Japan summit, SF6 was among the six greenhouse gases targeted for emissions reduction. The Environmental Protection Agency (EPA) has classified it as a "greenhouse gas". As such, EPA is interested in controlling SF6 release to the atmosphere and promoting competent SF6 management.

EPA has joined in "SF6 Emissions Reduction Partnerships" with many of the major U.S. utility companies. A memorandum of understanding (MOU) is drawn up between the EPA and the utility. Partnership requirements include:

- Maintaining ACCURATE INVENTORY OF SF6
- MONITORING and REDUCING the OVERALL SF6 LEAK RATE
- Implementation of SF6 RECYCLING
- Tightly MANAGING the use of SF6
- Yearly reporting of SF6 EMISSIONS

GREENHOUSE EFFECTS:

High temperatures such as those found on the sun produce short-wave radiation. A small percentage of this energy hits Earth. This radiation is absorbed; some of it is converted to heat and re-radiated as long-wavelength radiation in the form of infrared radiation (heat light).

In a greenhouse, glass is fairly transparent to short waves, but to longer waves it tends to be opaque. Thus, the inside of a greenhouse warms because of the trapped infrared. SF6 tends to absorb and trap infrared just as in a greenhouse; in this case, the heat warms the atmosphere.

CURRENT SITUATION:

To comply with the Partnership, utilities are faced with two primary decisions: How to effectively manage and document the use of SF6 on the system, and how to effectively detect SF6 leaks. To answer these questions, FPL did extensive analysis.

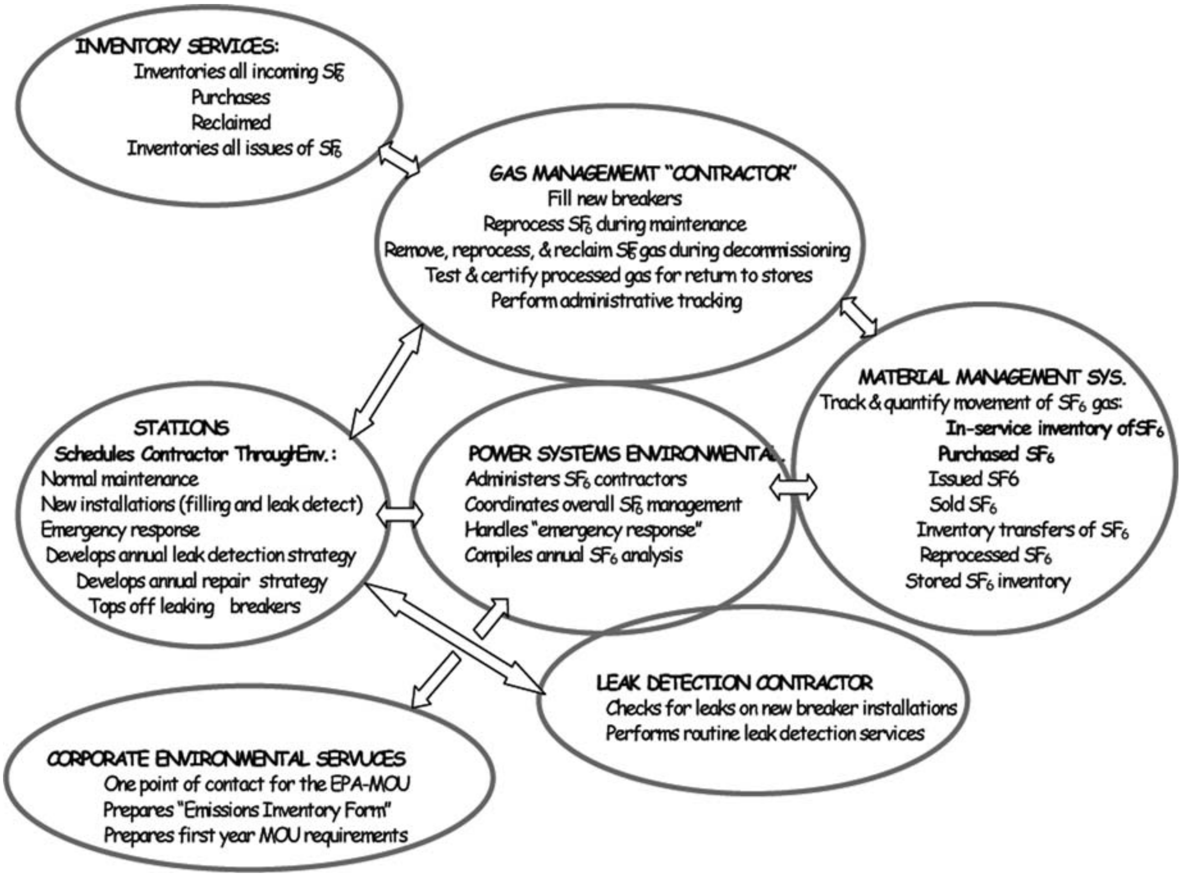
ANALYSIS:

Economic analysis indicated that outsourcing both SF6 management and leak detection was cost-effective. A management interaction diagram was then created to aid in developing structures, procedures, and bid specifications.

SF6 LEAK DETECTION:

In the area of leak detection, "Corporate Philosophy" was NEGOTIATED between departments. Agreement was reached on the following:

- All new breakers will be leak checked after installation.
- The existing population of SF6 breakers will be periodically checked.
- Equipment needing periodic filling will be documented and leak checked.
- Permanent fixes are preferred to temporary repairs (epoxies, etc.) where reasonably possible.
- Gas imaging technology will be used.


INVENTORY SERVICES:
Inventories all incoming SF_6
Purchases
Reclaimed
Inventories all issues of SF_6
GAS MANAGEMEMT "CONTRACTOR"
Fill new breakers
Reprocess SF_6 during maintenance
Remove, reprocess, & reclaim SF_6 gas during decommissioning
Test & certify processed gas for return to stores
Perform administrative tracking
MATERIAL MANAGEMENT SYS.
Track & quantify movement of SF_6 gas:
In-service inventory of SF_6
Purchased SF_6
Issued SF6
Sold SF_6
Inventory transfers of SF_6
Reprocessed SF_6
Stored SF_6 inventory
STATIONS
Schedules Contractor ThroughEnv.:
Normal maintenance
New installations (filling and leak detect)
Emergency response
Develops annual leak detection strategy
Develops annual repair strategy
Tops off leaking breakers
POWER SYSTEMS ENVIRONMENTAL
Administers SF_6 contractors
Coordinates overall SF_6 management
Handles "emergency response"
Compiles annual SF_6 analysis
LEAK DETECTION CONTRACTOR
Checks for leaks on new breaker installations
Performs routine leak detection services
CORPORATE ENVIRONMENTAL SERVUCES
One point of contact for the EPA-MOU
Prepares "Emissions Inventory Form"
Prepares first year MOU requirements

GAS IMAGING TECHNOLOGY:

Traditional leak detection methods using soap and sniffing equipment require that the breaker be removed from service. Waiting until data are collected on the periodic filling to determine leaking breakers takes time and does not provide information on where the leaks are. Some form of laser-based, remote sensing technology is generally needed if a large equipment population is to be tested in any reasonable time frame.

The technology "chosen" is known as backscatter absorption gas imaging (BAGI). This remote sensing technique is designed for the sole purpose of locating leaks or tracking gas clouds (McRae, 1993). The BAGI technique is a qualitative three-dimensional vapor visualization scheme that makes a normally invisible gas leak "visible" on a standard video display. The image of escaping gas allows the operator to identify the source of the leak and make a fairly accurate determination of its intensity. Gaseous leaks are detected and displayed in real time, but accurate determination of volume is not possible. This was not seen as a problem because the weight of SF6 gas used to top off leaking breakers is being tracked.

This technology was first developed for the Naval Sea Systems Command at the Lawrence Livermore National Laboratory. The idea was for the protection of sailors during initial surveillance of disabled marine vessels for the presence of toxic or flammable vapors. The system was patented under BAGI technology (US patent #4,555,627) and is marketed under the trademark "GasVue".

The advantage in using laser imaging systems is multifaceted: the exact location of leaks can be determined; the intensity of a leak is visible; equipment can remain in service while being tested; testing time is greatly reduced; and video documentation of the leaks provides positive evidence.

Figure 1 depicts how a laser camera illuminates the object under inspection, producing an infrared image from the backscattered laser light in much the same way that backscat-

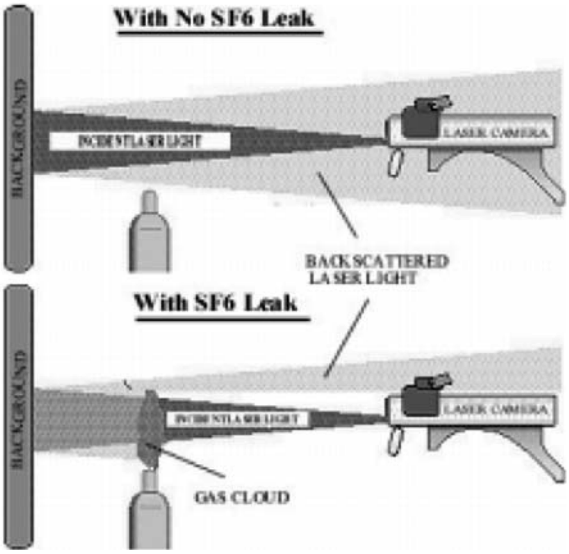


Figure 1

tered sunlight produces an image for a conventional TV camera. The detector in the laser camera is filtered so that it responds primarily to the wavelength of the laser light and ignores essentially all of the background thermal emission. Because there is no SF6 gas in the top view, the TV image is just of the background objects. However, when SF6 gas is present, as shown in the bottom view, it absorbs the laser light making the gas appear as a dark cloud. The higher the gas concentration, the greater the absorption, and the darker the gas cloud. In this manner, the normally invisible gas and its origin are visible on the TV monitor.

Figure 2 shows the inspection of an SF6 circuit breaker with laser system. The infrared image of the area under inspection is shown as the black-and-white inlay. This inlay is the same image that the operator will see in the laser camera's viewfinder. In actual practice, the motion of the leaking gas plume makes the leaking area noticeable. Obviously, this allows for very rapid inspection of the equipment while in-service, and the ability to pinpoint extremely small leaks.

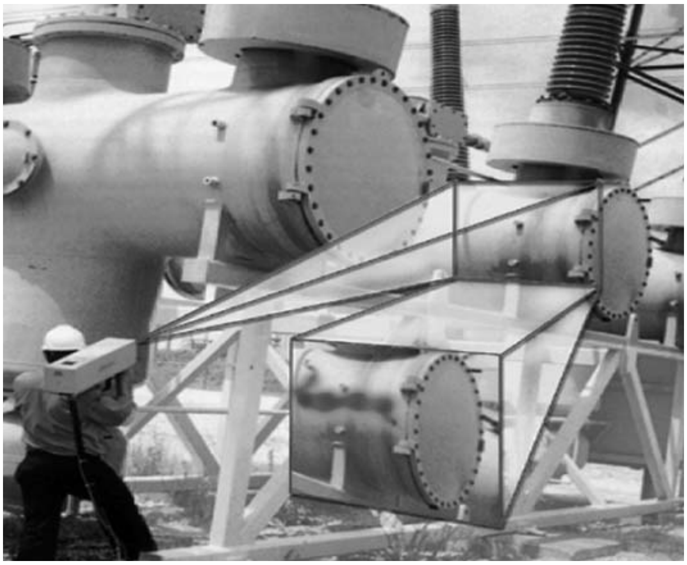


Figure 2

Furthermore, the results can be documented on video.

The technology does have its performance limits. The range of detection is generally between 20 and 30 meters but can be limited by weather (wind in particular). There must be a "reflective or backscattering surface" behind the leak, so it is not possible to visualize a gas plume against the sky. Too much free SF6 will obscure the leak if the area is indoors and the leaking is so bad that a "high density of SF6" surrounds the leaking area. The most favorable results have been obtained when the leak source was as close as possible, with low wind speed, and with the escaping gas coming directly at the laser cameras. As a final note, our field results have demonstrated that none of these limits caused insurmountable problems.

THE EQUIPMENT:

Machines now use CO2 laser power and video imaging camera equipment. The base unit and camera equipment are bulky, but research is being done to reduce the size (see Figure 3).

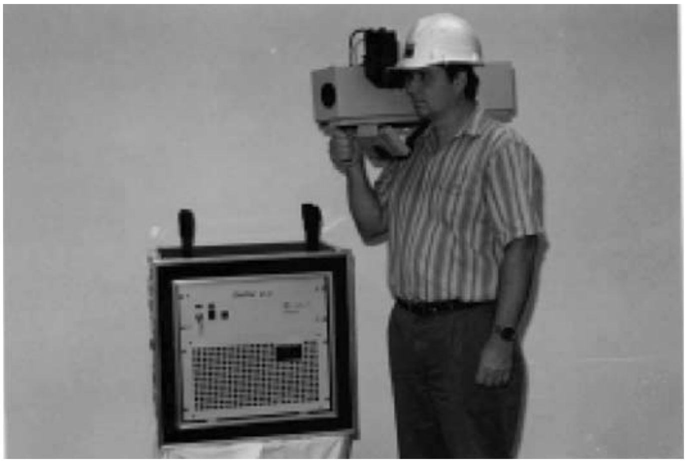
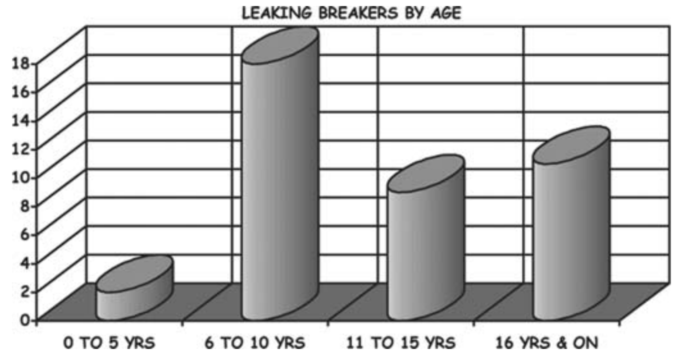


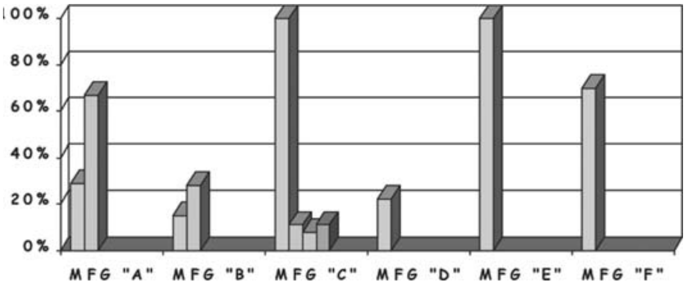
Figure 3

FIELD RESULTS:



AS ANTICIPATED, THE INFRARED LEAK DETECTION PROGRAM HAS PAID OFF:

- Within 4 months of implementation, 460 breakers had been tested.
- 9% (40 breakers) of the breaker population were found with detectable leaks.
- 85% of the leaking breakers were found to have significant leaks and had to be referred to "OPERATIONS" for scheduled repairs.
- 15% of the breaker leaks were minor enough to repair on the spot by the contractor.
- 5% of the leaking breakers were new and still within the warranty period.



WHERE WERE THE LEAKS FOUND?

- 62% of the leaks were found around fittings, piping connections, & gage connections.
- 16% were found around access gaskets.
- 12% were found on bushing seals.
- 5% were found around drive rods.
- 5% were found at welds.

CONCLUSIONS:

- "OUTSOURCING" LEAK DETECTION HAS BEEN ADVANTAGEOUS IN BOTH THE AREAS OF COST AND SPEED OF PROJECT COMPLETION.
- INFRARED LEAK DETECTION HAS ALLOWED FOR IDENTIFICATION OF SF6 LEAKS WHILE EQUIPMENT IS STILL IN SERVICE
- IN MANY CASES, INFRARED LEAK DETECTION HAS IDENTIFIED LEAKS PREVIOUSLY UNDETECTED USING TRADITIONAL TECHNIQUES.
- RESULTS HAVE BEEN AS ANTICIPATED — GOOD — AND ALL LEAKING BREAKERS HAVE EITHER BEEN REPAIRED, SCHEDULED FOR REPAIR, OR ARE SCHEDULED FOR REPLACEMENT.

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SWITCHGEAR DEVELOPMENTS OVER THE YEARS

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SYNOPSIS

The purpose of this paper is to examine the significant developments in MV and LV switchgear technology over the last few decades and why they are only recently beginning to benefit the users. A recent development now has sufficient field experience to show how, through innovative design, it has been possible to vastly improve an auto-reclosing circuit breaker.

INTRODUCTION

RELIABILITY

The main application of switchgear is in the protection of circuits against damage caused by faults and the restoration or preservation of supplies to as large a part of the system as possible following a fault. In this function they must add reliability to the system rather than contribute to system problems. Providing fault occurrences are rare, then system disruption caused by the switchgear, either for maintenance or operational problems has to be very rare. Hence the main objective of any switchgear development must be to improve the reliability of the switchgear itself as well as its performance as a protective device.

1960s SWITCHGEAR

Oil and air circuit breakers dominate LV and MV switchgear markets.

AIR CIRCUIT BREAKERS

Air has been used as the insulator in switchgear across the entire voltage range from miniature circuit breakers at domestic voltage to air-blast circuit breakers at transmission voltages up to 800kV. For the purpose of this paper, the term air circuit breaker will be used to describe a three-phase circuit breaker using air at atmospheric pressure as the insulator.

Early switches were plain-break which stretched an arc between a stationary and moving contact with no means of arc control. Arcing times were consequently long and voltage and current ratings limited. Performance was increased by the use of various arc control devices. Probably the best and therefore the most commonly used arc control device is the arc chute.

Arc chutes comprise a number of bare metal plates arranged at right angles to the length of the arc chute with spacers between the plates to allow the arc to be split up into a number of series smaller arcs, increasing its resistance and extracting heat. Eventually the arc is no longer able to sustain itself. When interrupting high short-circuit currents, the anode to cathode voltage drop is approximately 30V across each pair of plates. In DC circuit breakers, if enough plates are used in series, the arc voltage across the chute can be greater than the system voltage, forcing the current down to zero and thereby interrupting the current.

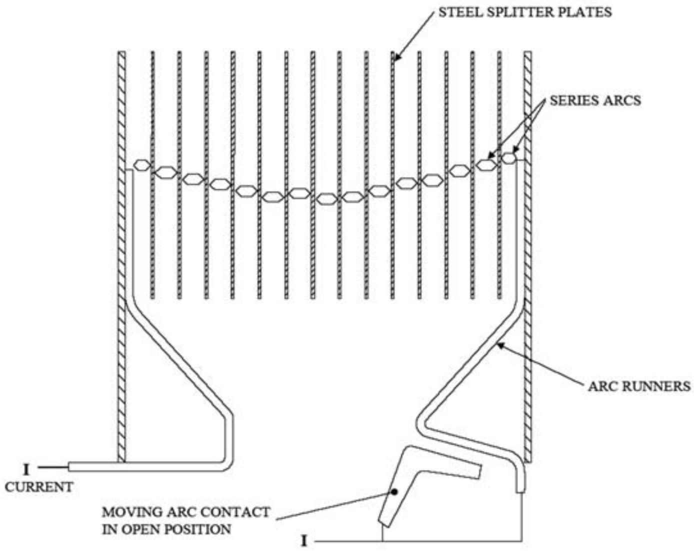

Fig. 1 (a) Cross-section through arc chute

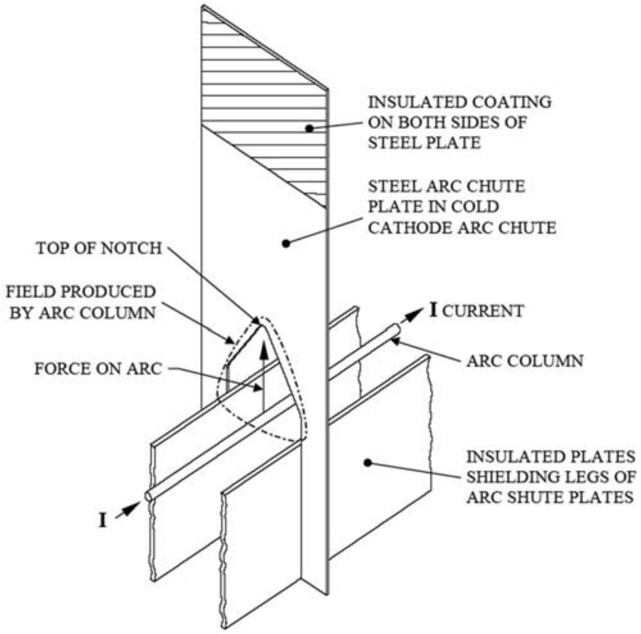

Fig. 1 (b) Electro-magnetic forces on arc

Fig 1(a) Shows the arc in its final position in a typical arc chute. The arc is initiated at the point of contact separation between the fixed and moving contacts and is transferred into the chute by electromagnetic and thermal forces, causing the arc to run away from the contacts along the arc runners. Arcing times are dependent upon current and voltage and can be relatively long.

In order to withstand the transient recovery voltage at the instant of interruption of an inductive current and also any transient over-voltages, the contact separation in air is large. The same electromagnetic forces which move the arc into the chute at high currents also act on the contacts attempting to blow them apart. Large contact pressure springs are used to counter the forces.

The combination of the long contact travel and the compression of heavy contact pressure and opening springs during the closing stroke necessitated a powerful operating mechanism.

OIL CIRCUIT BREAKERS

By the 1960s oil circuit breakers had also evolved from plain break interruption through to arc controlled interruption using the cross-jet explosion pot and now dominated the medium-voltage distribution switchgear market. However, they had similar operating mechanism energy requirements, in this case due to the long stroke and the need to move heavy contacts quickly through oil. Regular maintenance was needed to changed carbonised oil and worn contacts after a few fault interruptions.

SWITCHBOARDS

The regular maintenance requirements of the circuit breakers necessitated that they were withdrawable, either horizontally on rails or vertically. The ability to withdraw the circuit breakers from the switchboard allowed easy provision of physical isolation, circuit earthing and cable test facilities at the cost of an increase in front to back dimension for isolation/earthing.

In order to make the withdrawal of the circuit breaker and the use of the other operational facilities safe, ever more complex interlocking and shuttering arrangements evolved which made the switchgear more complex and difficult to operate. Withdrawal, interlocking, shuttering and earthing arrangements became mechanisms in their own right with associated failures contributing to the reduction of reliability of the switchgear.

SUMMARY OF 1960s SWITCHGEAR

- Oil and air interrupting technologies dominate LV and MV switchgear
- Interrupting devices require contact maintenance/oil change after a number of interruptions
- Powerful solenoid operating mechanisms with delicate trip latches required settings, adjustment and maintenance
- Withdrawable circuit breakers, added complexity and increased depth of switchboard
- Large and heavy switchgear, also large, heavy battery supply for high power solenoid mechanisms

1970s SWITCHGEAR

The major step forward in switchgear in this decade was the emergence of first vacuum, and later rotating, arc SF6 circuit breakers. These technologies have the shared advantages of long contact life and low operating energy requirements.

VACUUM CIRCUIT BREAKERS

Vacuum interrupters became commercially available in the early 1970s. The vacuum bottle is sealed for life and cannot be maintained and is capable of more fault interruptions than would be seen during the life of the switchgear without wearing out. The dielectric strength of the high vacuum is such that a contact travel of only 6mm can be used at a rated voltage of 12kV.

The advantages of the new technology was immediately obvious to several manufacturers and signalled the end of any further development in oil or air circuit breaker technology at medium voltage. The cost of the early vacuum interrupters was substantially more than comparably rated oil or air interrupters, which is probably why they do not have a significant usage even today at low voltage.

To offset the additional cost of the vacuum interrupters to compete with oil circuit breakers, three UK manufacturers produced fixed vacuum circuit breaker designs in order to reduce complexity, costs and size. The fixed design was made possible by the maintenance-free interrupters. However, the operating mechanism still demanded lubrication, occasional checks and resetting. Being too complex to rely upon for life, it had to be housed in a separate low-voltage compartment, connected to the three vacuum interrupters by a number of operating shafts, links, pivot points and insulators.

The first fixed designs failed to gain universal approval, mainly due to the leap of faith required in accepting manufacturers' claims that vacuum interrupters would prove to be truly maintenance free and would not lose their vacuum integrity after a period of time. Eastern Electricity who installed a large number of this type of switchgear from 1973 into primary substations claim that their operational experience has been trouble free.

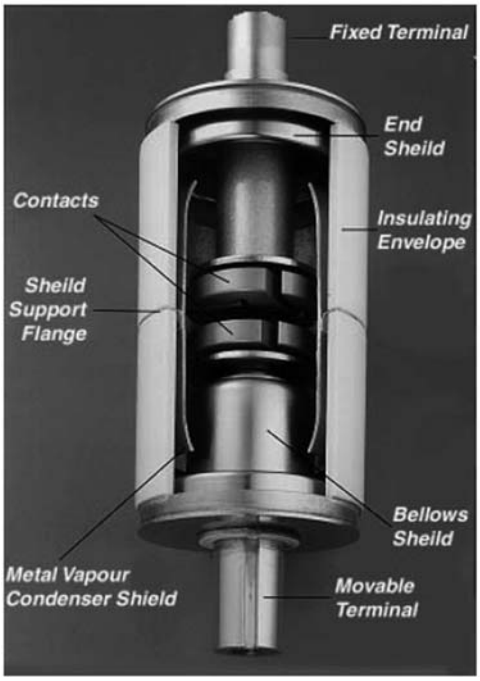

Fig. 2 Typical Vacuum Interrupter

ROTATING ARC SF6 CIRCUIT BREAKERS

This technology was developed by South Wales Switchgear. The rotating arc interrupter is as inexpensive as oil or air arc control devices, with almost the reliability and performance of a vacuum interrupter.

SF6 is a highly insulating, heavy, non-toxic gas which decomposes during the arcing process but very quickly recombines at current zero regaining its dielectric properties. Fault currents up to 20kA can be cleared at 12kV with a 50mm gap (approx) at a gas pressure of a 2.0 bar. The arc current is transferred during contact separation through a solenoid of a few turns of copper strip generating a magnetic field causing the arc to rotate around the inner ring of the solenoid. The rapid movement of the arc through the SF6 gas causes cooling and enables extinction at the first current zero at high fault currents.

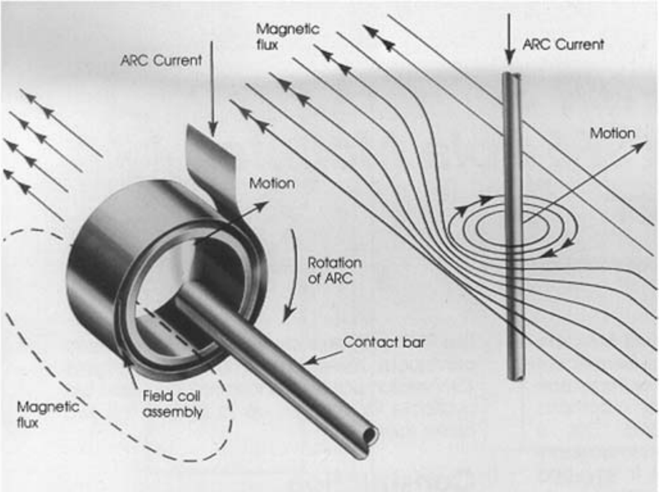

Fig. 3 Rotating arc principal

SUMMARY OF 1970S SWITCHGEAR

- Vacuum and rotating arc SF6 interrupters enable low energy, maintenance free interrupting devices
- Reduced energy solenoid operating mechanism designs still require settings, adjustment and maintenance
- Fixed vacuum designs introduced but did not catch on due to lack of service experience with vacuum interrupters

1980s SWITCHGEAR

No new interrupting devices have become commercially available in MV or LV since the advent of vacuum interrupters and rotating arc SF6. During the 1980s the main thrust of development activity was to provide better, more cost-effective circuit breakers using the new technologies. Vacuum interrupters have become smaller for a given rating and less expensive. Nearly all new circuit breakers developed during this period were withdrawable designs.

To reduce the size of substation batteries and chargers that provided the power source for opening and tripping of the circuit breakers, motor-wound spring mechanisms became standard equipment on all medium-voltage and low-voltage circuit breakers. A spring is charged by an electric motor drawing a few amps over a period of a few seconds in place of the earlier closing solenoid that took a current of many tens of amps for a fraction of a second. The spring energy is released by a smaller solenoid releasing a latch. As the spring relaxes, it drives the mechanism components, compressing the contact pressure and opening springs and forcing the moving and fixed contacts of the interrupter together.

While the substation battery (until the widespread use of electronic protection relays) could be reduced in size, the mechanisms became even more complex compared to solenoid mechanisms. Despite claims from some manufacturers, users were experiencing an increase in switchgear problems.

SUMMARY OF 1980s SWITCHGEAR

- Oil and air circuit breakers go out of production, vast majority of new switchgear put into service are vacuum or SF6
- Emphasis on production engineering to produce cost reduced designs
- Motor-wound spring mechanisms and withdrawable designs become the order of the day

1990s SWITCHGEAR

Vacuum circuit breakers have emerged during this decade as by far the most preferred technology for primary substation medium-voltage switchgear, as field service experience shows almost zero failure rate of vacuum interrupters and interrupter prices fall.

The fixed switchgear concept has made a comeback with SF6 insulated vacuum switchgear and air insulated SF6 switchgear with conventional mechanisms in the low-voltage compartment driving the interrupters through linkages.

The most significant advance in switchgear technology in many years has come with the introduction of the GVR pole mounted auto-recloser which included a magnetic actuator mechanism and other radical innovations which are presently shaping new developments in medium-voltage switchgear. The operating mechanism is now as reliable as the interrupter.

WHAT IS AN AUTO-RECLOSER?

Essentially, an auto-recloser is a pole-top mounted reclosing circuit breaker which is used to protect sections of the overhead line supply network, usually in remote locations. An electronic control unit operates a mechanism which opens the main circuit contacts when it detects fault current on the overhead lines, which it monitors. If the fault is still present, the auto-recloser will open and close up to two more times before finally locking out. If the fault has cleared during a dead time, the auto-recloser sequence ends with the main contacts closed and the supply re-established to the customer.

Why is it so important for auto-reclosers to be highly reliable and require little or no maintenance?

- Auto-reclosers are intended to enhance the reliability of the distribution network.
- Unlike other forms of switchgear which are used as a protection device and very rarely operate (like fuses), an auto-recloser's normal duty is to operate many times under short circuit (fault) conditions.
- They are installed far out into the network in remote locations

1n 1993 when the development of the GVR began, there were several well-established manufacturers of auto-reclosers. Other switchgear companies were considering entering this market which is growing, especially in the UK as the electricity regulator OFFER is demanding that the privatised electricity companies (RECs) increase the quality of supply on the overhead line networks. However, the RECs were reluctant to place large orders due to the problems that existed with the available auto-reclosers and were looking at other alternatives, such as insulated overhead lines.

An auto-recloser has without doubt the most arduous duty of any circuit breaker. In some areas of the world they can clear more than 1000 transient faults per annum! In order for any new auto-recloser to be successful, the concept had to be a radical departure from the existing designs and had to meet the "fit and forget" criteria. This was achieved by the development of a number of innovations and with around 20,000 GVRs in service field experience has confirmed the maintenance-free aspect of the design.

The main innovation was the use of a magnetic actuator operating mechanism, which is at least as reliable as the vacuum interrupters, but there are less obvious innovations and good design practices that contribute to the product reliability.

MAGNETIC ACTUATOR

The magnetic actuator is basically a solenoid containing powerful rare earth (neodemium iron boron) permanent magnets which have been commercially available for about 10 years that latch the armature at either end of its stroke holding the interrupter contacts open or closed. A single moving part replaces over 100 moving parts contained in a conventional circuit breaker mechanism linkage. Figure 4 shows a comparison of a typical motor-wound spring mechanism and a magnetic actuator on the same scale.

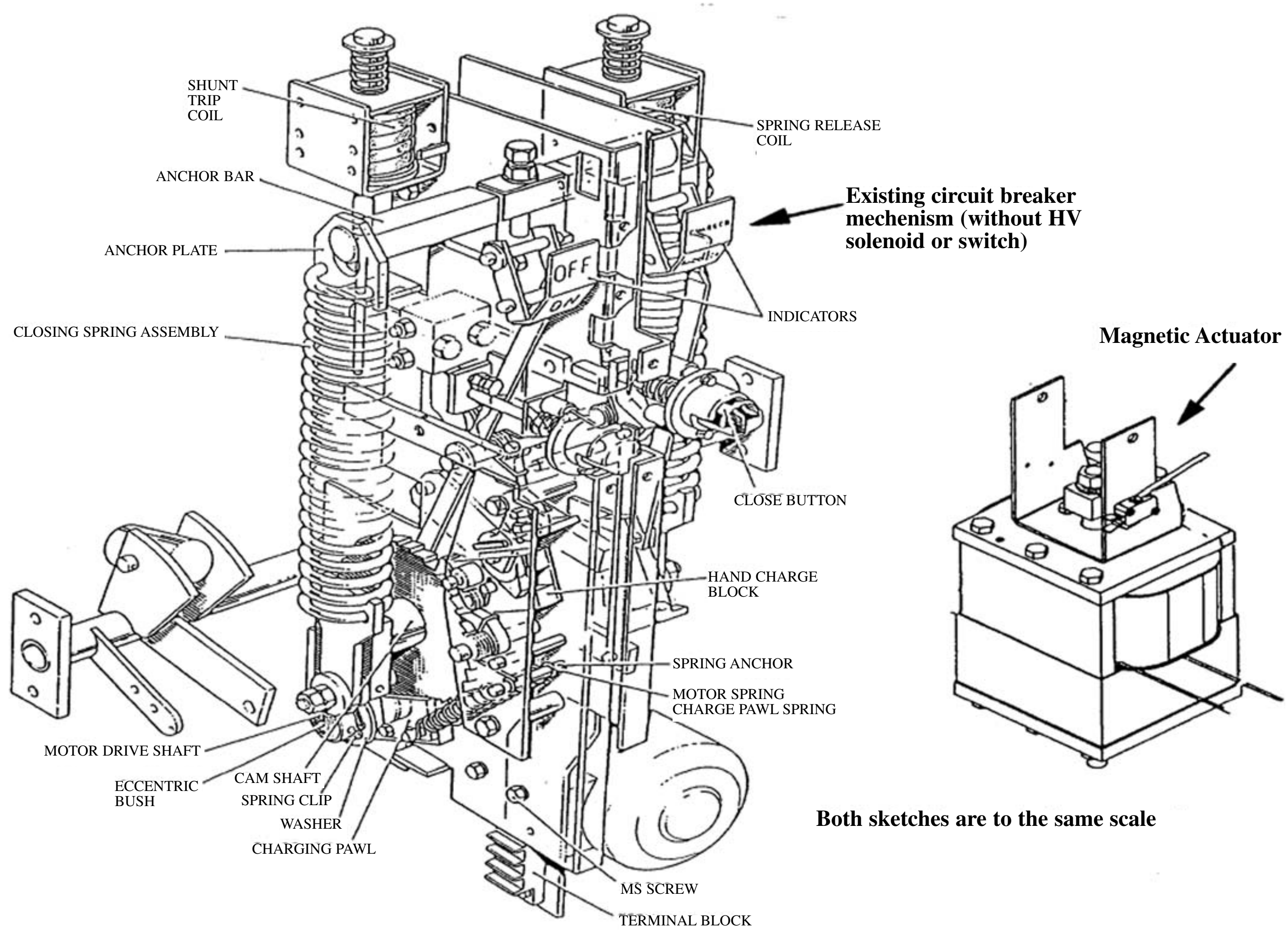

Fig. 4 Comparison of typical motor-wound spring mechanism and magnetic actuator

The force/travel characteristics of the magnetic actuator match closely the requirements of a circuit breaker, particularly when closing onto fault currents. With good design, the actuator can provide a direct drive to the moving contact system without the need for complex linkages and is highly efficient, reducing the current pulse drawn from the substation battery to manageable levels.

The success of the GVR auto-recloser has sparked a new wave of developments in the MV switchgear industry. It is now almost impossible in most parts of the world to sell an auto-recloser that does not use a magnetic actuator. Most leading manufacturers are also fitting magnetic actuators in place of the existing mechanisms in their circuit breakers used in their current designs of primary switchgear, which are horizontally withdrawable.

The lessons of the past show that it is not effective to simply fit a better technology component to an existing design concept.

2000 TO TODAY

New designs of switchgear will evolve, designed from scratch with every component as simple and reliable as possible, to capitalize on the potential of the magnetic actuator mechanism and to be as trouble free as the latest interrupter technology. This concept should be applied to low-voltage switchgear, finally replacing the old technology air circuit breakers at this voltage and perhaps later to EHV switchgear.

A medium-voltage switchgear of such a design is the Eclipse (shown on the next page).

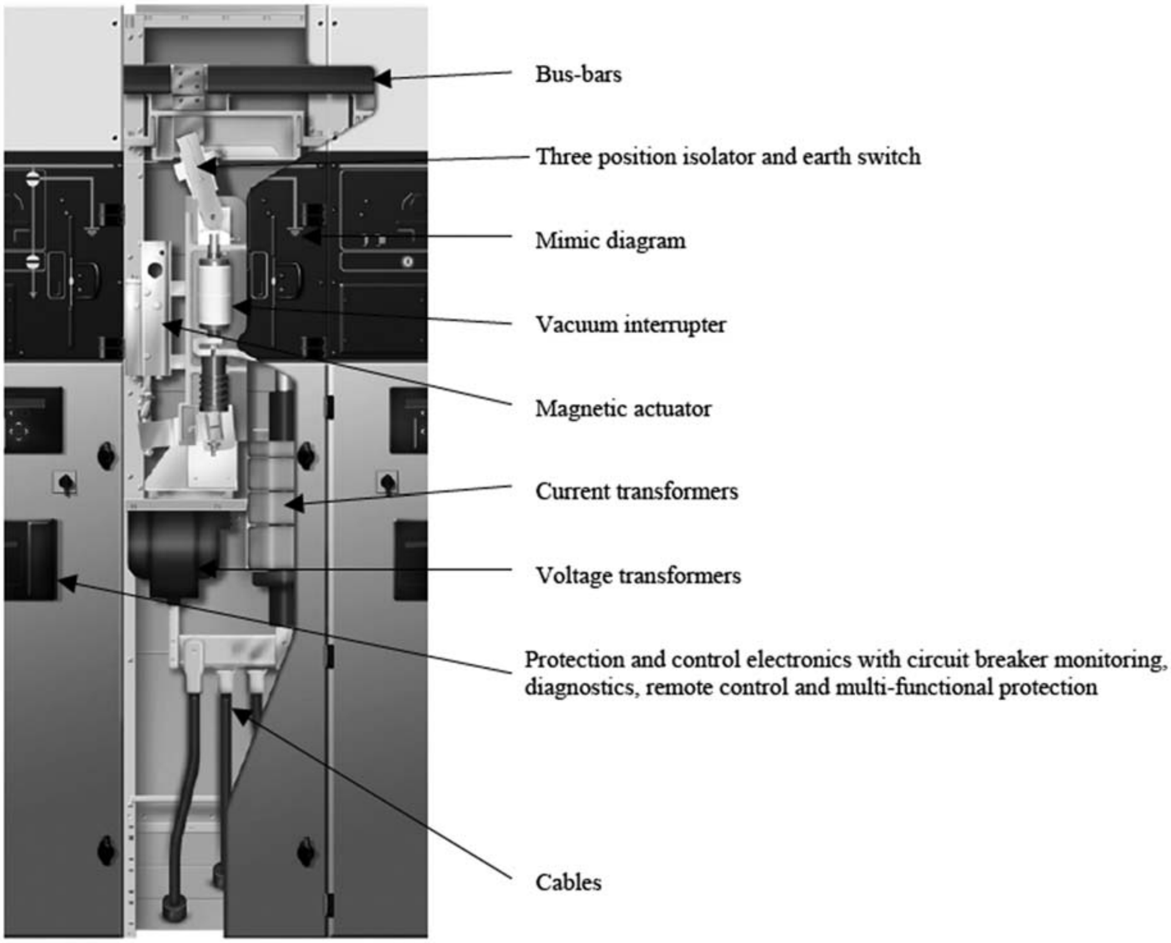
Bus-bars
Three position isolator and earth switch
Mimic diagram
Vacuum interrupter
Magnetic actuator
Current transformers
Voltage transformers
Protection and control electronics with circuit breaker monitoring, diagnostics, remote control and multi-functional protection
Cables

Fig 5 Eclipse – fixed vacuum air insulated switchgear with magnetic actuator drive

This minimalist design is the lightest and dimensionally smallest in its class; for military use there may be no need to two-tier the circuit breakers within the cubicle. Some preliminary investigational shock tests have been carried out on this switchgear.

SHOCK WITHSTAND

The intrinsically simple design of the Eclipse circuit breaker and magnetic actuator, lends itself to being easily adapted to meet shock requirements.

COMPARISON WITH CONVENTIONAL CIRCUIT BREAKERS

A conventional circuit breaker mechanism incorporates catches for tripping and for closing spring release (in the case of a stored energy mechanism). In addition, anti-rebound latches to prevent main contacts closing during shock are incorporated. All of these features need to be balanced for good shock performance further adding to the complexity of the mechanism. The magnetic actuator, as previously described, provides a robust operating mechanism with a single moving part. As the solenoid plunger is magnetically latched in both the closed and open positions, the need to provide for anti-rebound catches and balancing features is eliminated.

The use of the “fixed pattern” philosophy further provides increased reliability and durability. Incorporating an integral isolator has allowed the circuit breaker carriage to be rigidly fixed within the cubicle, reducing the complexity of interlocking and isolating features. Rigidly fixing the circuit breaker eliminates the relative motion between circuit breaker and cassette during shock, particularly when subjected to a sinusoidal shock wave as experienced on the deck shock machine (DSM).

Again, the fixed pattern philosophy brings improvements in reliability through the elimination of wiping secondary connections which would require particular detail to prevent contacts parting during shock.

TEST EXPERIENCE

Recently, an Eclipse circuit breaker was shock tested in accordance with BR8470 on the DERA West Drayton DSM the tests were investigational and in co-operation with MOD(N) ME242. With very little modification to the commercial design currently being developed, shock levels of 30g vertical, horizontal side to side and horizontal back to back were attained with little damage being sustained. A shock level of 58g in the vertical direction was reached before the circuit breaker sustained irreparable damage.

The results of these tests and subsequent examination of the tested equipment show that a 70g “commercial off the shelf” design is feasible, with some modifications. If a 30g maximum shock level was chosen for future warships than a design is immediately available.

CONCLUSIONS

The combination of magnetic actuator and vacuum interrupters has enabled maintenance-free for life circuit breakers. Switchgear can now be made more compact, simple and reliable by bolting the circuit breaker into the high-voltage compartment.

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MEDIUM VOLTAGE, METAL-CLAD ARC RESISTANT SWITCHGEAR: ENHANCING WORKPLACE SAFETY

Thomas P. McNamara, P.E., Manager, Development Engineering, ABB Inc., Power Technologies Medium Voltage

INTRODUCTION

As more and more emphasis is placed on personnel safety in the workplace, the need for safer system planning, procedures, tools, and products continually increases. Although the probability of an arcing fault inside metal-clad switchgear is low, the cost in terms of personnel safety and equipment damage is high when an arcing fault occurs. OSHA, NFPA, and IEEE have recognized the hazards associated with arcing faults in electrical systems by specifically addressing measures to minimize the possibility of an arcing fault, and to mitigate its effects on personnel. This paper discusses these issues, emphasizing the role that arc resistant switchgear plays in providing a safer work environment.

COMMON CAUSES OF ARC FAULTS IN SWITCHGEAR

Arc faults within switchgear can be caused by a number of factors, including:

a. Loss of insulating properties resulting from elevated temperatures. This can be caused by applying the equipment above its continuous rating and from improperly torqued or aligned contact joints. Thermographic monitoring may be used to monitor temperature rises so that preventive measures can be taken.

b. The presence of dust, contamination, or moisture on insulating surfaces. These conditions lead to tracking across insulating surfaces, providing a path for conduction between two different potentials. Heaters can be effective in minimizing condensation on internal conductors. The condition of the insulation should be monitored as part of an effective maintenance program, especially in harsher environments.

c. Voids in insulation, which eventually lead to failure of the insulation when stressed at high voltages. Epoxy bus insulation has demonstrated a greatly improved life expectancy based on its homogeneous composition.

d. Human error. The implementation of disciplined work procedures, effective personnel training, and proper tools can minimize the possibility of human error causing an arc fault incident.

SUMMARY OF ARC FAULT CHARACTERISTICS

An arc fault within an arc-resistant switchgear enclosure is typically characterized by the following four phases:

a. Compression phase: The compression phase starts at t=0 when the arc starts to burn and continues until the pressure can no longer increase.

b. Expansion phase: The expansion phase starts when the maximum pressure has been reached and the pressure relief flaps have opened. This phase lasts approximately 5 to 10 milliseconds.

c. Emission phase: The emission phase occurs when all the necessary pressure relief flaps have opened so that inside air, where the arc burns, is exhausted outside the cell. This continues until the gas in the cubicle reaches the arc temperature. This phase typically lasts 50 to 100 milliseconds in small cubicles, and in larger cubicles it can be considerably longer.

d. Thermal phase: The thermal phase lasts until the arc is extinguished. An arc emits radiation because of its extremely high temperature (10,000 to 20,000 degrees K in the center). The thermal energy emitted during this phase heats, melts, and vaporizes parts of the cubicles and the components mounted in them. The greatest damage typically occurs during this phase, when the thermal stress caused by the radiated heat is responsible for severe burns and ignition of clothing.

INDUSTRY RECOGNITION OF ARC FLASH HAZARDS

The pertinent documents governing arc flash hazards are:

- OSHA 29 Code of Federal Regulations (CFR) Part 1910, Subpart S
- NFPA 70E-2000, "Standard for Electrical Safety Requirements for Employee Workplaces"
- IEEE 1584-2002, "Guide for Arc Flash Hazard Analysis"
- IEEE C37.20.7-2001, "IEEE Guide for Testing Medium-Voltage Metal-Enclosed Switchgear for Internal Arcing Faults"

OSHA 29 CFR 1910, Subpart S mandates that safe practices be implemented to prevent shock or injuries due to direct or indirect contact with energized conductors. It also addresses the fact that workers who may be exposed to electrical hazards must be qualified and that provisions for the appropriate personnel protective equipment must be made.

NFPA 70E details the steps needed to comply with the OSHA requirements. Specifically, NFPA 70E addresses:

- Worker training
- Appropriate and safe tools
- Safety program with responsibilities clearly identified
- Arc flash hazard calculations
- Personal protective equipment (PPE)
- Equipment warning labels

IEEE Standard 1584-2002 provides a means to calculate the incident energy resulting from an arc flash.

Per NFPA 70E, incident energy is "the amount of energy impressed on a surface, a certain distance from the source, generated during an electrical arc event".

It is not considered safe to work around energized equipment generally. However, if and when this is deemed necessary by the owner, the use of the properly rated PPE by properly trained personnel is required.

The incident energy level is used to determine the flash protection boundary (the surrounding area where the incident energy is equal to or greater than 1.2 calories/cm2). This incident energy level exposes personnel to potential second-degree burns.

The incident energy also is used to determine the appropriate PPE required for the application. The incident energy level is dependent on various factors, including system operating configurations, voltage, length of the arc, arcing current, protective device settings, time to clear, and distance from arc fault to workers. In a given work environment, the calculation needs to be performed at various locations where any of these variables will change. Note that the highest level of arcing current does not always result in the highest incident energy level. A lower level of current that results in a longer arcing duration may cause higher incident energy levels at the workers' location. Care must be exercised to prescribe the appropriate PPE for the application. Overly conservative requirements can restrict worker movement, vision, hearing, and comfort level unnecessarily. This in itself can be the cause of an unsafe situation.

An incident energy level above 40 cal/cm2 is considered unsafe, even with the prescribed PPE.

Regardless of the incident energy level, additional practical steps can be taken to improve the safety level of the work environment. These include the use of arc resistant switchgear, provisions for closed door or remote circuit breaker racking and operation, and special protective schemes to minimize arc fault durations and magnitudes.

OVERVIEW - EVOLUTION OF ARC RESISTANT SWITCHGEAR STANDARDS

Interest in arc resistant switchgear designs and ratings was evident thirty years ago in Europe, where medium voltage switchgear typically included uninsulated bus, which increased the likelihood of an arc fault occurrence. As a result, a draft Annex AA to IEC 298 (currently IEC60298), "A.C. Metal-Enclosed Switchgear and Controlgear for Rated Voltages Above 1 kV and Up to and Including 52 kV", was created in 1976 and was eventually approved by the IEC in 1981.

As a result of the interest in improving safety in the workplace in North America, Annex AA was used as a guideline in the preparation of the EEMAC G14-1-1987, "Procedure for Testing the Resistance of Metal-Clad Switchgear Under Conditions of Arcing Due to an Internal Fault". Refinements were made in EEMAC G14-1 based on "lessons learned" in the preceding years of applying Annex AA. EEMAC G14-1-1987 defines three accessibility types:

Type A: "switchgear with arc resistant construction at the front only"

Type B: "switchgear with arc resistant construction at the front, back and sides"

Type C: "switchgear with arc resistant construction at the front, back and sides, and between compartments within the same cell or adjacent cells" (exception: adjacent main bus compartments)

IEEE C37.20.7-2001, "IEEE Guide for Testing Medium-Voltage Metal-Enclosed Switchgear for Internal Arcing Faults", is based on these two predecessor documents, but also includes improvements as deemed appropriate. This document is currently being reviewed by the working group and will be refined further in the next revision. Part of this revision process will include an attempt to harmonize the requirements with the current IEC practices. IEEE C37.20.7 also defines three accessibility types:

Type 1: "switchgear with arc resistant designs or features at the freely accessible front of the equipment only".

Type 2: "switchgear with arc resistant designs or features at the freely accessible exterior (front, back, and sides) of the equipment only".

Annex A to IEEE C37.20.7-2001 addresses a third accessibility type that addresses arc-resistance designs or features between adjacent compartments within the same cell or adjacent cells (with the exception of the main bus compartments). These are identified by the use of suffix "C" as follows:

Type 1C: "switchgear with arc resistant designs or features at the freely accessible front of the equipment only", along with arc-resistance designs or features between adjacent compartments within the same cell or adjacent cells (with the exception of the main bus compartments)

Type 2C: "switchgear with arc-resistant designs or features at the freely accessible exterior (front, back, and sides) of the equipment only", along with arc-resistance designs or features between adjacent compartments within the same cell or adjacent cells (with the exception of the main bus compartments)

The testing associated with each of these documents is based on all covers and doors being properly secured, and all vents and vent flaps set to their correct operating positions. Therefore, the ratings assigned based on testing to these standards apply only under these conditions.

Testing is performed at the prescribed voltage and current levels with the specified flammable cotton indicators strategically positioned to detect the escape of hazardous gases. Assessment criteria include:

1. Door, covers, etc. do not open. Bowing or other distortion is permitted except on those which are to be used to mount relays, meters, etc.
2. That no parts are ejected into the vertical plane defined by the accessibility type
3. There are no openings caused by direct contact with an arc
4. That no indicators ignite as a result of escaping gases or particles
5. That all grounding connections remain effective

CHARACTERISTICS OF ARC RESISTANT SWITCHGEAR DESIGNS

Arc resistant switchgear is characterized by some special design features necessary to achieve the required ratings. Typically, these include:

a. Robust construction to contain the internal arc pressure and direct it to the exhaust chambers designed for the purpose of safely venting the gases

b. Movable vent flaps that open due to the arc fault pressure, increasing the volume containing the arc products

c. Special ventilation designs with flaps that are open under normal operating conditions, but slam shut when an arc fault occurs

d. Closed door circuit breaker racking and operation

ABB's SafeGear utilizes a patented series of vent flaps in conjunction with an arc chamber to safely vent the arc gases away from personnel. This design makes it possible to stack the circuit breakers two-high within one cell.

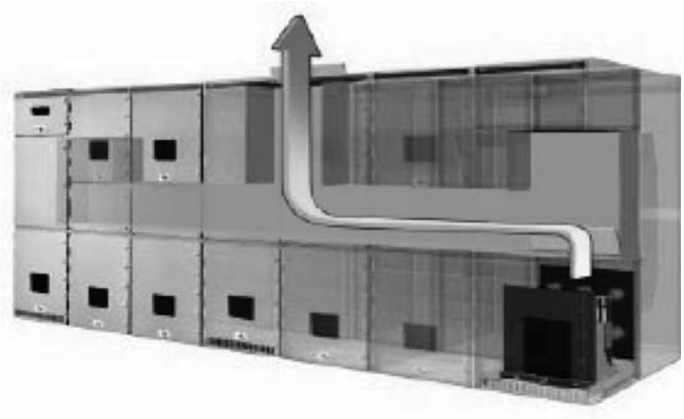


Figure 1. Internal horizontal and vertical arc chamber vents arc gases safely away from personnel.

Front doors, rear and side panels are designed, secured, and tested to ensure that they withstand the potentially high pressures until the relief flaps open and pressure subsides, without being blown from the cubicle or allowing dangerous hot gases to be released to the front, rear, or sides of the switchgear.

Doors are reinforced with channel steel, and secured with special hinges and hardware. Interlocking flanges and gasket material are used to seal in flames and keep hot gases from igniting flammable materials near the switchgear.

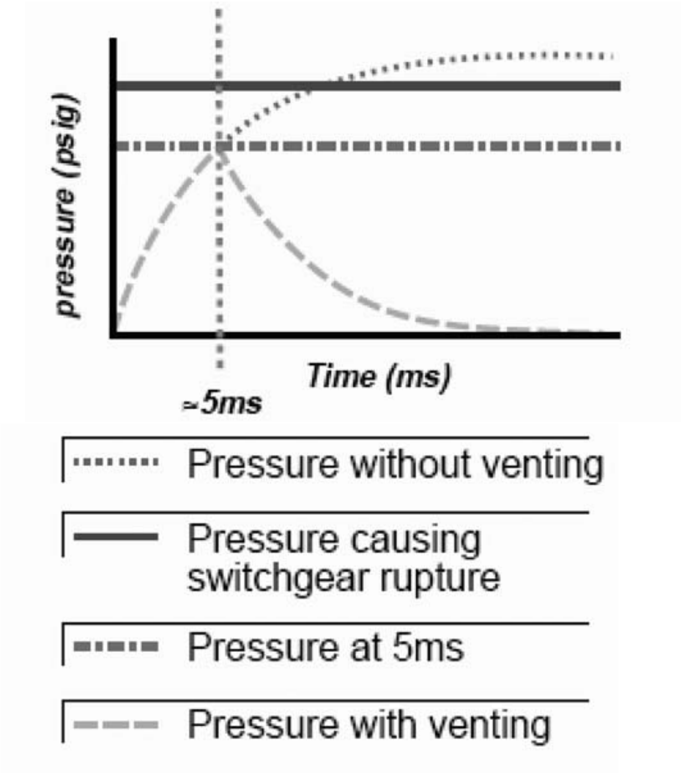


Figure 2. Typical pressure vs. time relationship for switchgear internal arc fault.

The use of a double wall construction between cells has been demonstrated to be very effective in withstanding the heat and pressure created by the arc fault. The heat dissipation and resistance to burnthrough is enhanced considerably by the use of double 14 gauge side sheets separated by an air gap of approximately 3/16 inch.

The integrity of the low-voltage control and protective device circuitry is critical. Low-voltage compartments, which contain the protective relays, meters, devices, and wiring, should be separate reinforced modules. This protects not only the devices themselves, but the control bus and wiring which may otherwise be destroyed as a result of the arc fault. This is extremely important as the protective scheme is being relied on to limit the duration of the arc fault.

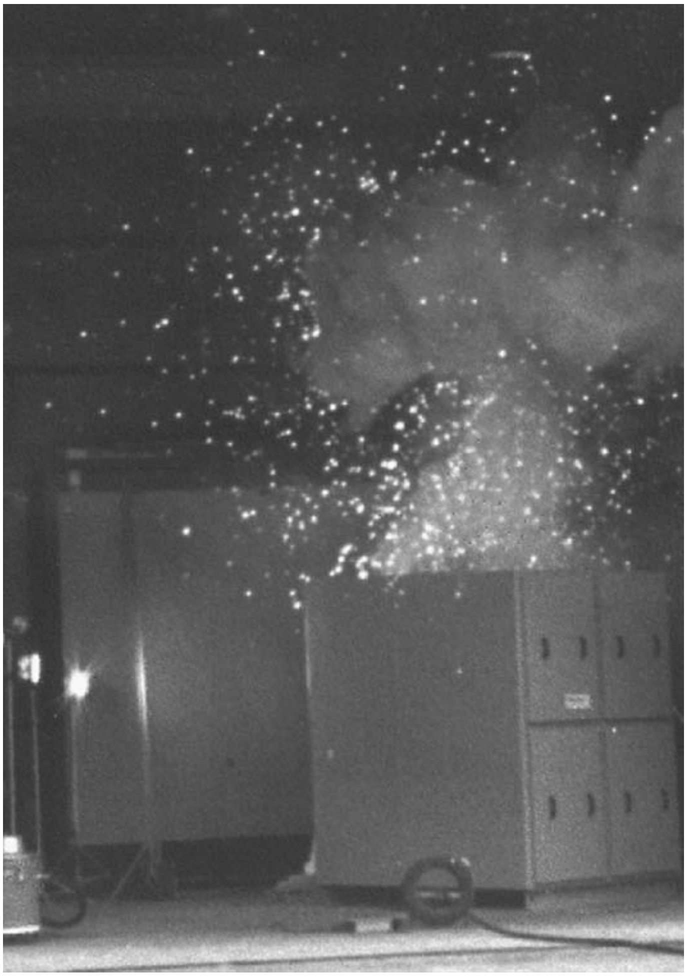
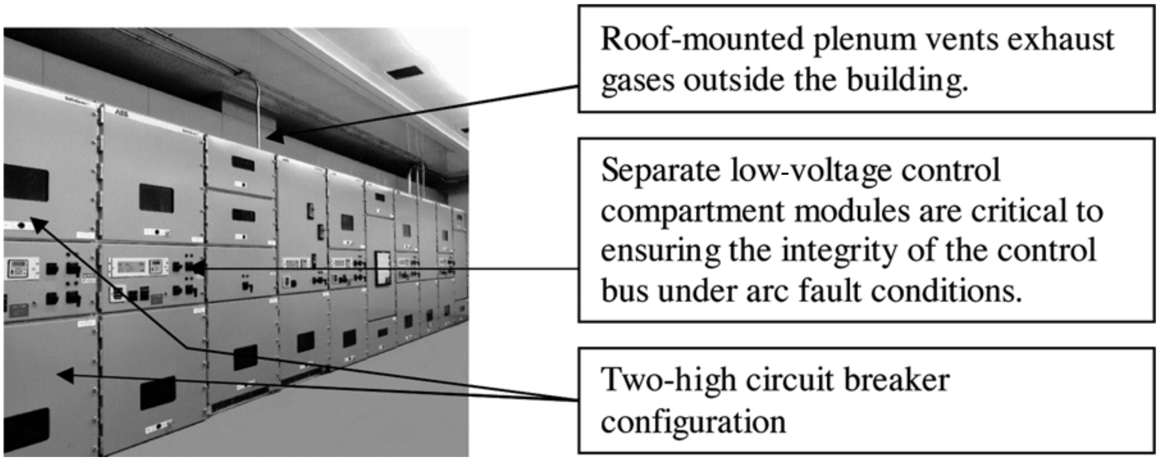


Figure 3. Successful arc test on 15 kV metal-clad switchgear.

Consideration must also be given to provide sufficient clearance above the switchgear to allow the gases to be dispersed properly and not to be reflected back into the area that could be occupied by personnel.

Where appropriate clearances are not possible due to the design of the building, an exhaust plenum can be provided to safely vent the gases outside the building to an area that is not accessible to personnel.

The plenum design must be tested to verify that the potential back pressure does not cause a failure of the arc resistant integrity of the equipment.


Roof-mounted plenum vents exhaust gases outside the building.

Separate low-voltage control compartment modules are critical to ensuring the integrity of the control bus under arc fault conditions.

Two-high circuit breaker configuration

Figure 4. Exhaust plenum mounted on roof of two-high switchgear in PDC building.

SYSTEM PROTECTION APPROACHES

The system protection scheme should be designed to limit the total energy that results from internal arc faults, and specifically, to limit the current magnitude and duration to values that are within the arc-resistant ratings of the switchgear. Various approaches can be used to achieve this, including:

1. Arc detection system: Very fast identification of an arcing fault can be achieved by sensing a combination of light, sound, pressure, and current rate of rise. Using these parameters, an arcing fault can be identified in 2 to 4 milliseconds, at which time a trip signal is sent to the circuit breakers supplying power to the fault. In this situation, the equipment is subjected to the peak pressure because of the tripping time of the circuit breaker, but the duration of the fault, and therefore, the overall energy level, is reduced. Peak pressure occurs within approximately 20 milliseconds. Total clearing time with this approach will be approximately 70 to 100 milliseconds.

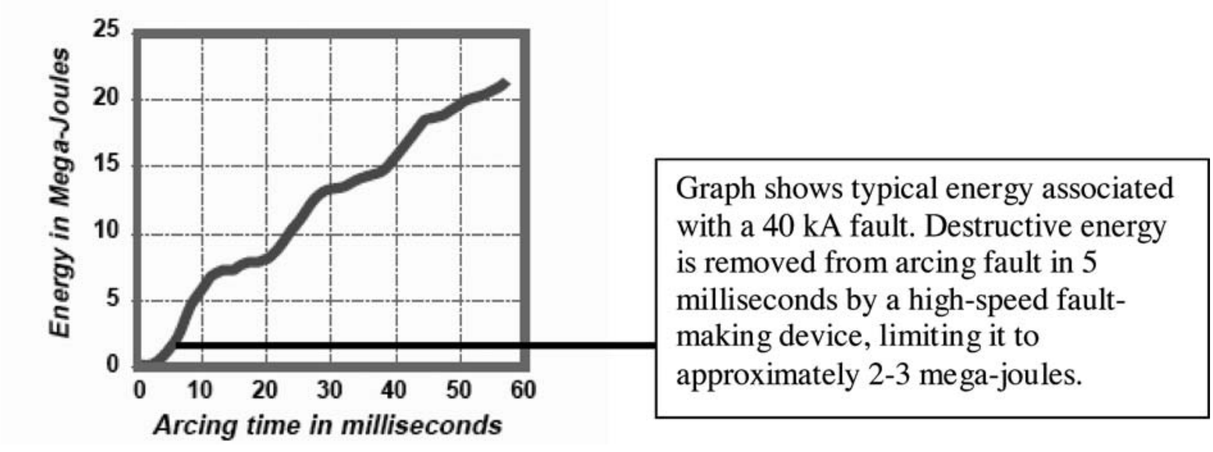
2. High-speed fault making devices: Using sensors similar to those described above for the arc detection system, upon sensing an arcing fault, a very high speed fault making device can be activated to apply a three-phase fault on the power system. The energy is diverted from the arcing fault to the three-phase bus circuit, which is designed to withstand this energy. This effectively removes the source of energy to the destructive arcing fault. Simultaneously, a trip signal is sent to the circuit breakers supplying power to the faulted area. As in the arc detection system above, the total clearing time will be approximately 70 to 100 milliseconds.

However, the energy is now contained in the bus bars. The arcing fault energy was diverted within 4 to 5 milliseconds. Therefore, the danger and destruction caused by the arcing fault is limited significantly. The three-phase fault is applied before the switchgear is subjected to the peak pressure of the arcing fault. The resulting display and equipment damage is negligible.

3. Differential relaying scheme: By monitoring and summing the currents flowing in and out of the defined protective zone, the differential scheme can be set up to be very sensitive and to operate very quickly. When the sum of the currents in and out of the protective zone do not equal zero, the high speed differential relay picks up and trips the appropriate circuit breakers that are supplying power to the zone. With high speed differential relaying, the total interruption time will be less than 100 milliseconds. Although this scheme is typically fast, sensitive, and limits energy by reducing the fault duration, it only protects the defined differential zone.

4. Grounding schemes and ground fault protection:

i. Solidly grounded system: Ground fault protection can be used to sense and interrupt ground fault currents. With no intentional impedance in the ground return circuit, ground cur-



Graph shows typical energy associated with a 40 kA fault. Destructive energy is removed from arcing fault in 5 milliseconds by a high-speed fault-making device, limiting it to approximately 2-3 mega-joules.

Figure 5. High-speed fault-making device limits destructive energy significantly

rents can be high. Settings dictated by coordination with upstream and downstream devices can cause tripping to be delayed. Additional protection, e.g., differential zone protection, is advisable.

ii. Low-resistance grounded system: The low-resistance grounding system reduces the probability of a single phase-to-ground arcing fault. If one occurs, it may evolve into a multi-phase arcing fault. Ground fault relaying should be set to quickly identify this condition and remove all power sources supplying the fault.

iii. High resistance grounded system: With the ground current limited by the high resistance, system operation can continue after the first phase-to-ground fault occurs. However, the ground fault should be located and removed quickly to avoid overvoltage stresses, which increase the probability of a second phase to ground fault.

iv. Ungrounded system: Since the ground current is limited by the phase-to-ground capacitive reactance, system operation can continue after the first phase-to-ground fault occurs. Similar to the high resistance grounded system, the ground fault should be located and removed quickly to avoid overvoltage stresses, which increase the probability of a second phase-to-ground fault.

5. Partial discharge monitoring: A method of predicting potential failures is to monitor switchgear insulation for partial discharge levels while in service. The data obtained can be used to identify trends over time, which enables the user to correct the problem before catastrophic failure occurs.

SUMMARY

Metal-clad switchgear, with fully Insulated primary conductors, major parts of primary circuits isolated in grounded metal, and primary circuits isolated from secondary circuits by grounded metal, is designed to minimize the potential for internal arc faults. However, if and when they occur, arc faults can be catastrophic in terms of danger to personnel and destruction of equipment. Proper application, maintenance, and operation by qualified personnel can further reduce the probability of internal arc faults.

With ever increasing interest in workplace safety, the need to address the hazards of arcing faults and arc flash is recognized throughout the electrical industry. OSHA, NFPA, and IEEE have each published documents that cover the requirements and guidelines associated with these potential issues. OSHA 29 CFR 1910, Subpart S mandates the requirements, NFPA 70E defines the steps necessary to meet the OSHA requirements, and IEEE 1584 provides a means to calculate the incident energies, which enable the user to prescribe the appropriate personnel protective equipment. In selecting the proper personnel protective equipment, note that the highest arc fault currents do not always result in the highest incident energy. A lower arc fault current for a longer duration may result in a higher incident energy level than a high arc fault current for a short duration.

Arc-resistant switchgear can provide an additional level of safety over conventional switchgear, by directing the arc gases, in the event of an internal arc fault, away from the area where workers may be present (in front of, beside, or behind the switchgear). The industry standards governing the arc testing of arc resistant switchgear have evolved from IEC in the 1970s, to EEMAC in the late 1980s, to IEEE in 2001.

Protective devices and schemes can also be used to reduce incident energy levels by quickly identifying arc faults and minimizing the associated destructive energy. This can be done by reducing the arc fault current magnitude and/or time duration. If the protective scheme is dependent on control power, it is important to ensure that the low voltage control bus is designed in such a way that it will not be destroyed in the event of an internal arc fault.

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MEDIUM-VOLTAGE GIS SWITCHGEAR: WHAT YOU SHOULD KNOW

Eaton

Medium-voltage (5 to 38 kV) gas insulated switchgear (GIS) differs greatly from the medium-voltage air insulated switchgear commonly used in North America. Instead of using air and solid insulation materials, GIS switchgear has the vacuum interrupter and bare bus conductors in a sealed housing filled with an insulating gas.

Environmental Concerns - The insulating gas used in MV GIS switchgear, sulfur hexafluoride (SF6), is a highly potent greenhouse gas with a global warming potential 23,900 times greater than CO2. SF6 also has an atmospheric life of 3,200 years, so it will contribute to global warming for a very long time. One pound of SF6 has the global warming equivalent of 11 tons of CO2. (Source: EPA website www.epa.gov/electricpower-sf6)

Safety Concerns - In its normal state, SF6 gas is colorless, odorless, non-flammable, and non-toxic to humans. However, under high temperature conditions (> 350 degrees F), SF6 decomposes into products that are toxic and corrosive. Decomposition by-products can occur when SF6 is exposed to spark discharges, partial discharges, switching arcs and failure arcing. These byproducts, in the form of gases or powders, can cause the following conditions in humans: irritation to the eyes, nose, and throat, pulmonary edema and other lung damage, skin and eye burns, nasal congestion, bronchitis; powders may cause rashes. (Source: EPA website www.epa.gov/electricpower-sf6)

ANSI certification results in equipment that meets rigorous U.S. operating requirements. GIS equipment is not tested to these standards, and definitely is not tested to IEEE guide for testing metal-enclosed switchgear for internal arcing faults. IEC 62271-200 - metal enclosed MV switchgear, accepts internal arc tests to be performed with air instead of SF6, for environmental reasons.

However, it should be noted that the test results may differ if the tests were done with SF6. When a dielectric failure occurs in a GIS, the arc generally will not be extinguished by the SF6, and could lead to internal pressure build up and cause holes in metal walls due to concentrated burning of the arc. GIS manufacturers just state that the GIS equipment is "inherently" arc resistant, but in reality an arc can very well live within the GIS. Also it is well known that all SF6 containments leak, therefore, the chances of having an issue with GIS is more prevalent than ever having an arc issue within non arc resistant switchgear. Utilizing other solutions, such as designs that use complete single pole solid insulation, partial discharge sensors for insulation diagnostics, and remote racking for safety, the non arc resistant solution easily exceeds the safety of GIS.

Special Handling Procedures - Due to the safety concerns, special handling procedures are recommended for heavily arced SF6 including the use of personal protective equipment (PPE - i.e., respiratory device, protective clothing such as rubber gloves, footwear, goggles) for removal/handling of solid SF6 byproducts.

Contaminated SF6 gas must either be filtered on-site using special mobile equipment or removed for off-site filtering or destruction using trained personnel. (Source: EPA website www.epa.gov/electricpower-sf6)

Installation Concerns - The most significant installation issues involve the need for proper alignment. The foundation must be level and in a single plane to allow for proper assembly of the shipping sections. The foundation height can only vary by 1 mm per meter, with a maximum deviation of 2 mm over the full length of the assembly. After installation of the GIS shipping groups, equipment must be sealed and SF6 is filled at site. To maintain dielectric withstand levels, special cable termination is required in GIS. The design also limits number of cables/phase that can be installed in a given circuit. Another issue is power cable connections are not accessible without disassembling the switchgear. (Source: IEEE Transaction on Industry Applications, Vol. 40, No. 5, September / October 2004 and Eaton experience.)

Operation & Maintenance Concerns - Because SF6 gas provides insulation of internal components, draw out circuit breaker designs are not possible. Most local codes require that the design of equipment incorporate a means to visually verify the isolating function of disconnect devices. In the GIS switchgear, this requires a means to visually verify the position of the three-position switch. To meet this requirement, some manufacturers install miniature video cameras, and associated lighting, both mounted external to the SF6 gas enclosure. The video leads are brought to the front panel of the switchgear, and a monitoring device is provided to view the position of the switch. (Source: IEEE Transaction on Industry Applications, Vol. 40, No. 5, September / October 2004)

End of Life / Recycling Concerns - Used SF6 gas must be recovered by trained professionals, then stored and transported in US Department of Transportation (DOT) approved cylinders for the final recycle process. DOT regulations require equipment containing SF6 gas at pressures greater than 25 psig at 68°F to be certified to transport compressed gas. DOT regulations require cylinders of SF6 gas with a gross weight greater than 220 lbs. It must include a shipping paper. Recyclers equipped to handle metals exposed to SF6 gas should process the remaining metal parts of the switchgear. (Source: EPRI Guidelines for Safe Handling of SF6, DOT CFR 49 Chapter 1 Subchapter C)

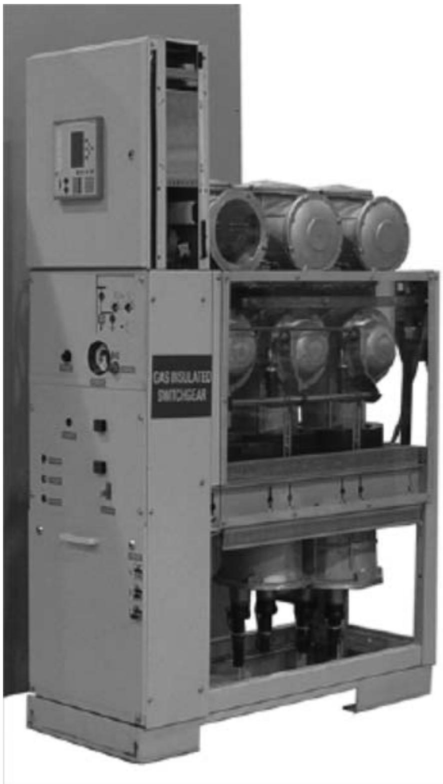
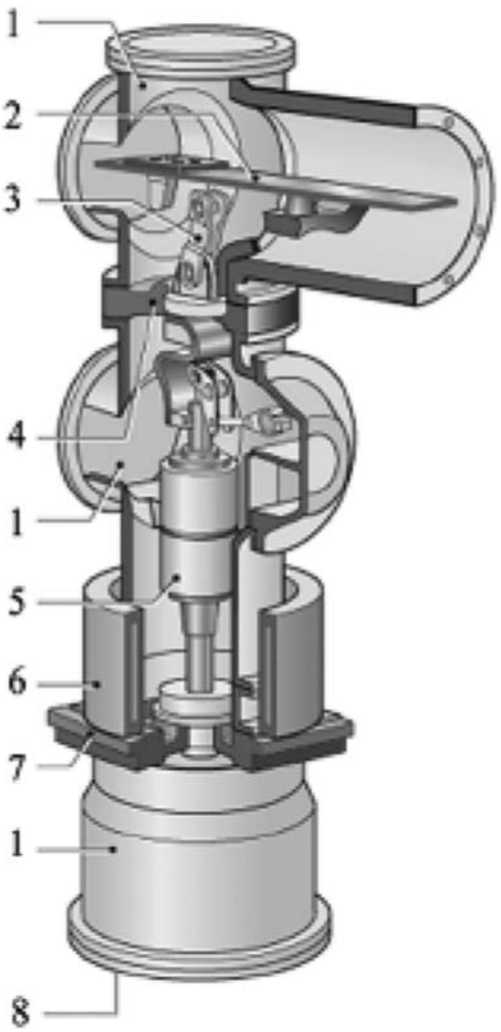


Fig. 1: Typical circuit breaker unit in GIS switchgear



1 - cast aluminum housing
2 - main bus bars with sliding supports
3 - three-position selector switch
4 - gas tight bushing
5 - vacuum interrupter
6 - toroidal current transformer
7 - capacitive voltage transformer
8 - shock-proof (safe-to-touch) cable termination (not shown)

GIS differs greatly from traditional MV Metal Clad switchgear widely used in North America. A view of one pole of a typical unit of GIS switchgear is shown in Fig. 1. As in air insulated Metal Clad switchgear, vacuum circuit breakers are used for interruption. MV GIS switchgear differs from high-voltage GIS switchgear in that the SF6 gas is used for its insulating properties, not for interruption. Conventional MC switchgear relies on a combination of air and solid insulating materials, but GIS switchgear uses bare bus conductors on insulating supports, immersed in insulating gas.

CONCLUSION

Due to the environmental concerns, installing medium-voltage GIS switchgear is not consistent with the Sustainability Principles and Greenhouse Gas reduction goals of many leading edge corporations and institutions. The safety and special handling concerns could raise issues with internal Environmental Health & Safety policies. Finally, the installation, operation & maintenance and end of life/recycling concerns associated with medium-voltage GIS switchgear can raise the total cost of ownership and may not be the best value solution.

With a global product portfolio, Eaton has a variety of MV switchgear solutions that utilize environmentally responsible and safety conscious medium-voltage insulation materials. These alternative solutions include air insulated and solid insulated switchgear designs that avoid the use of SF6 gas and can offer a lower total cost of ownership over the complete life cycle of your medium-voltage equipment.

A COMPANY STORY IN ADVANCED TECHNOLOGIES FOR HIGH-VOLTAGE SWITCHGEAR

D. Dufournet, G. Montillet, AREVA T&D

1. INTRODUCTION

As early as 1957, the “Ateliers of Constructions Electriques de Delle” decided to use the properties of the SF6 gas for insulation and interrupting medium [1]. “Delle” started research and development work on the first puffer SF6 circuit breaker in 1959, on the basis of our own design in Macon, France.

This decision was purely exploratory, as “Delle” was already manufacturing minimum oil circuit breakers and air blast circuit breakers for the world.

The first SF6 gas industrial developments were in the medium-voltage ranges. These developments were a metal clad circuit breaker for flameproof switchboards, an extra-compact distribution installation and a circuit breaker for locomotive. These endeavours have confirmed the advantages of a technique which uses SF6 as a low pressure level concurrently with the auto-pneumatic blast system to interrupt the arc - very similar to minimum oil technology - called later “puffer”. [2].

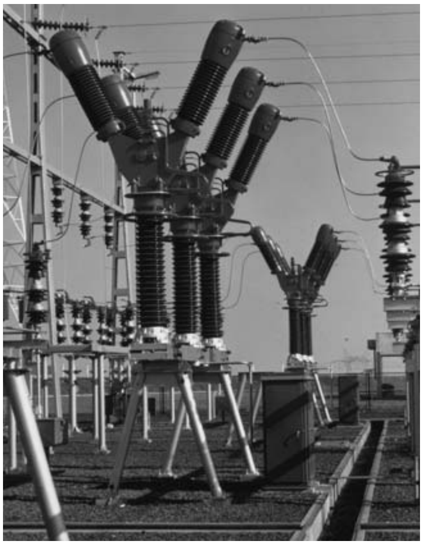


Figure 1. Minimum Oil circuit breaker 145 kV type Orthojector

High-voltage SF6 circuit breakers with self-blast interrupters have found world-wide acceptance because of their obvious advantages: the low operating energy required reduces the stress and wear of the mechanical components and thus improves significantly the overall reliability of the circuit breaker. This switching principle was first introduced in the high-voltage area about 40 years ago, starting with the voltage level of 72.5 kV. Today, this technique is available up to 800 kV and above. Furthermore, it is used for our generator circuit breaker applications type FKG with short circuit currents of 63 kA and above.

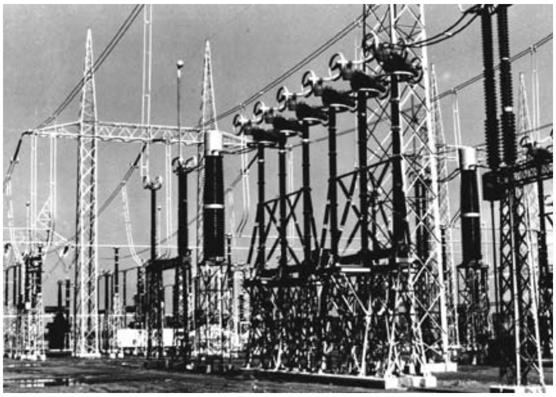


Figure 2. Air blast circuit breaker type PK12 applied to 765 kV in North America.

Service experience shows that the expectations of the designers at the beginning, with respect to reliability and day-to-day operation, have been fulfilled completely.

This paper will deal with the following items:

- A brief history of circuit breakers.
- A description of the switching principles since SF6 was first introduced in the switchgear technology in 1959.
- The progress in self-blast technology of interrupting chambers with spring operating mechanisms. This is the most common technology for circuit breakers today.
- A comparison of single motion and double motion principles - both technologies are used in combination with the self-blast principle.
- Outlook for the future with respect to the operating mechanism energy needed for all voltage levels.

2. BRIEF HISTORY

The oldest circuit breakers still in existence in North America and in Europe were developed with a small oil volume, due to the bombing of World War II, (they were bulk oil prior to 1939) and were called “Orthojector”. In 1961 it could be said that we had developed this type of extinguishing medium in oil for the last 30 years [3]. These circuit breakers evolved in type HPGE and OR “small oil content” for outdoor use of 24 kV to 245 kV in the early 1970s. A tentative attempt was performed to extend them to 765 kV, 50 kA, but the number of interrupting units in series was too numerous. These 245 kV circuit breakers were rated at a maximum of 7500 MVA at 245 kV, (or 18 kA by today’s standard) with interrupting capabilities for kilometric fault that became known in the industry as short line fault.

Then came the air-blast circuit breaker type AE for very high-voltage (EHV) up to 550 kV in Russia, (type AE17) in the 1960s for higher interrupting capabilities. By this time, we had reached a standard value of 30,000 A short circuit interrupting. An improved version came later on, called the type PK (for Pneumatic and Kilometric Fault) that was very successful in North America and in Europe. We could reach some top values of 80 and 90 kA by the late 1970s and at very fast speeds, such as the 1-cycle 550 kV breakers used by the Bureau of Reclamation, in Washington State, USA. Many circuit breakers at 550 kV and 800 kV are still in operation today.

The first high-voltage SF6 circuit breaker with a high short-circuit current capability was produced in 1959. This dead tank puffer circuit breaker could interrupt 20 kA under 25.5 kV and was used in explosion proof applications. These performances were already significant, with one chamber per pole, and were called “Orthofluor”.

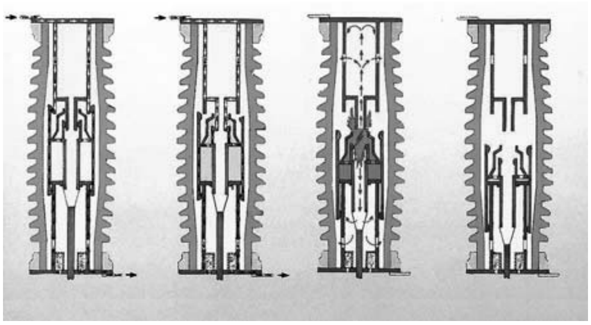


Figure 3: Puffer type circuit breaker

The high pressure needed for short-circuit interruption was generated by the movement of the mobile part itself. The basic idea was hardly new as it was already patented in 1930 by Société Générale de Constructions Electriques et Mécaniques [4].

The “puffer” technique, shown in figure 3, was applied in the first live tank gas insulated circuit breaker installed in France in 1969 at 245 kV.

The excellent properties of SF6 lead to the fast extension of this technique in the ’70s and to its use for the development of circuit breakers with high interrupting capability, up to 800 kV as in the FX line of circuit breakers [5].

The achievement around 1983 of the first single-break 245 kV type FX and the corresponding 420 kV, 550 kV and 800 kV, with respectively two, three and four chambers per pole, lead to the dominance of SF6 circuit breakers in the complete high-voltage range [6].

Several characteristics of SF6 “puffer” circuit breakers can explain their success:

- Simplicity of the interrupting chamber which does not need an auxiliary chamber for breaking;
- Autonomy provided by the puffer technique;
- The possibility to obtain the highest performances, up to 63 kA, with a reduced number of interrupting chambers (figure 4);
- Short interrupting time of 2 to 2.5 cycles at 60 Hz;
- High electrical endurance, allowing at least 25 years of operation without reconditioning;
- Possible compact solutions when used for GIS or Hybrid switchgears;
- Integrated closing resistors or synchronized operations to reduce switching over voltages;
- Reliability and availability;
- Low noise level;
- No compressor for SF6 gas as many competitors were developing and manufacturing double pressure SF6 gas circuit breakers when we were the only manufacturer to supply a single pressure circuit breaker.

The reduction in the number of interrupting chambers per pole has led to a considerable simplification of circuit breakers as the number of parts was decreased as well as the number of seals. As a direct consequence, the reliability of circuit breakers was improved, as verified later on by CIGRE surveys.

Figure 4 : 800 kV 50 kA circuit breaker type FX with closing resistors

3. SELF-BLAST TECHNOLOGY

The last 15 years have seen the development of the self-blast technique for SF6 interrupting chambers. This technique has proven to be very efficient and has been widely applied for high-voltage circuit breakers up to 800 kV. It has allowed the development of new ranges of circuit breakers operated by low energy spring-operated mechanisms [7] [8] [9].

Another aim of this evolution was to further increase the reliability by reducing dynamic forces in the pole and its mechanism.

These developments have been facilitated by the progress made in digital simulations that were widely used to optimize the geometry of the interrupting chamber and the mechanics between the poles and the mechanism.

The reduction of operating energy was mainly achieved by lowering energy used for gas compression and by making a larger use of arc energy to produce the pressure necessary to quench the arc and obtain current interruption.

Low current interruption, up to about 30% of rated short-circuit current, is obtained by a puffer blast where the overpressure necessary to quench the arc is produced by gas compression in a volume limited by a fixed piston and a moving cylinder.

Figure 5 shows the interruption principle of a self-blast (or double volume) chamber, where a valve (V) was introduced between the expansion and the compression volume.

When interrupting low currents, the valve (V) opens under the effect of the overpressure generated in the compression volume. The interruption of the arc is made as in a puffer circuit breaker thanks to the compression of the gas obtained by the piston action.

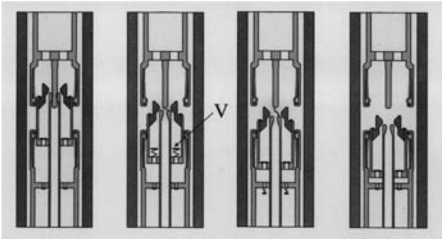


Figure 5: Self blast (or double volume) interrupting chamber

In the case of high current interruption, the arc energy produces a high overpressure in the expansion volume, which leads to the closure of the valve (V), and thus isolating the expansion volume from the compression volume. The overpressure necessary for breaking is obtained by the optimal use of the thermal effect and of the nozzle clogging effect produced whenever the cross-section of the arc significantly reduces the exhaust of gas in the nozzle.

This technique, known as “self blast” has now been used extensively for more than 15 years for the development of many types of interrupting chambers and circuit breakers (Figure 6).

Better knowledge of arc interruption obtained by digital simulations and validation of performances by interrupting

Figure 6: Live tank circuit breaker 145 kV with spring-operating mechanism and self blast interrupting chambers

tests, contribute to a higher reliability of these self-blast circuit breakers. In addition, the reduction in operating energy allowed by the self-blast technique leads to a higher mechanical endurance.

3.1. DOUBLE MOTION PRINCIPLE

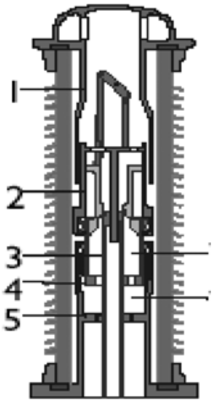
The self-blast technology was further optimized by using the "double-motion" principle. This leads to a further reduction of the operating energy by reducing the kinetic energy consumed during opening. The method consists of displacing the two arcing contacts in opposite directions. With such a system, it was possible to drastically reduce the necessary opening energy for circuit breakers.

Figure 7 shows the arcing chamber of a circuit breaker with the double motion principle. The pole columns are equipped with helical springs mounted in the crankcase.

These springs contain the necessary energy for an opening operation. The energy of the spring is transmitted to the arcing chamber via an insulating rod.

In order to interrupt an arc, the contact system must have sufficient velocity to avoid reignitions. Furthermore, a pressure rise must be generated to establish a gas flow in the chamber.

The movable upper contact system is connected to the nozzle of the arcing chamber via a linkage system. This allows movement of both arcing contacts in opposite directions. Therefore the velocity of one contact can be reduced by 50% because the relative velocity of both contacts is still 100%. The necessary kinetic energy scales with the square of the velocity, allows – theoretically – an energy reduction in the opening spring by a factor of 4. In reality, this value can't be achieved because the moving mass has to be increased. As in the self-blast technique described in chapter 3, the arc itself mostly establishes the pressure rise.



1.	Fixed upper contact
2	Movable upper contact system
3	Pressure chamber
4	Piston
5	Lower contact system
Vt	Expansion volume
Vc	Compression volume

Figure 7: Double motion interrupting chamber

Because the pressure generation depends on the level of the short-circuit current, an additional small piston is necessary to interrupt small currents. Small pistons mean less operating energy.

The combination of both double movement and self-blast technique allows a drastic reduction in the opening energy. As a consequence of this, the design principle was simplified.

3.2. PARTICULAR CASE OF GENERATOR CIRCUIT BREAKERS

Generator circuit breakers are connected between a generator and the step-up voltage transformer. They are generally used at the outlet of high power generators (100 MVA to 1800 MVA) in order to protect them in a sure, quick and economic manner. Such circuit breakers must be able to allow the passage of high permanent currents under continuous service (6 300 A to 40 000 A), and have a high breaking capacity (63 kA to 275 kA).

They belong to the medium voltage range, but the TRV withstand capability is such that the interrupting principles developed for the high-voltage range have been used. Two particular embodiments of the thermal blast and self blast techniques have been developed and applied to generator circuit breakers.

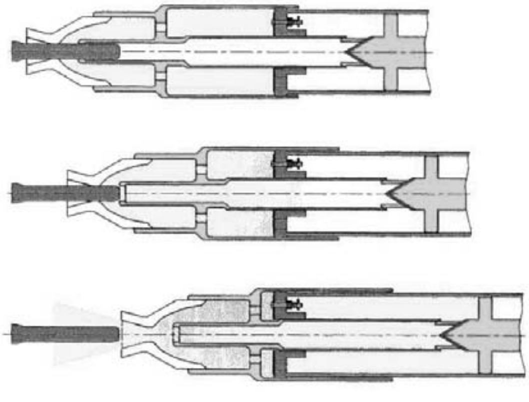


Figure 8: Thermal blast chamber with arc-assisted opening

3.2.1. THERMAL BLAST CHAMBER WITH ARC-ASSISTED OPENING

In this interruption principle arc energy is used, on the one hand to generate the blast by thermal expansion and, on the other hand, to accelerate the moving part of the circuit breaker when interrupting high currents (Figure 8).

The overpressure produced by the arc energy downstream of the interruption zone is applied on an auxiliary piston linked with the moving part. The resulting force accelerates the moving part, thus increasing the energy available for tripping.

It is possible with this interrupting principle to increase, by about 30%, the tripping energy delivered by the operating mechanism and to maintain the opening speed irrespective of the short circuit current.

It is obviously better suited to circuit breakers with high breaking currents such as generator circuit breakers.

3.2.2. SELF-BLAST CHAMBER WITH REAR EXHAUST

This principle works as follows (figure 9):

In the first phase, the relative movement of the piston and the blast cylinder is used to compress the gas in the compression volume Vc. This overpressure opens the valve C and is then transmitted to expansion volume Vt.

In the second phase, gas in volume Vc is exhausted to the rear through openings (O).

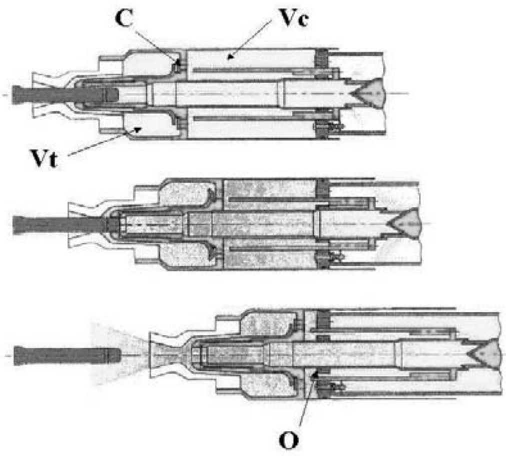


Figure 9: Self-blast chamber with rear exhaust

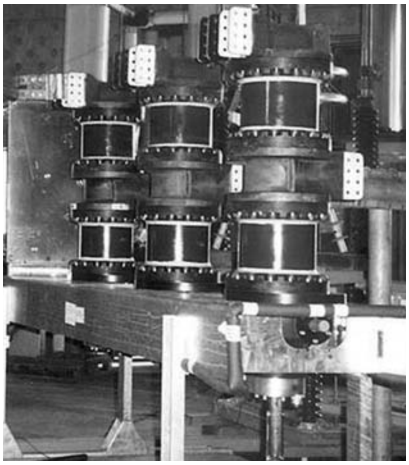


Figure 10: Generator circuit breaker SF6 17,5 kV 63kA 60 Hz

The gas compression is sufficient for the interruption of low currents. During high short-circuit current interruption, volume Vt is pressurized by the thermal energy of the arc. This high pressure closes valve C, the pressure in volume Vc on the other hand is limited by an outflow of gas through the openings (O). The high overpressure generated in volume Vt produces the quenching blast necessary to extinguish the arc at current zero.

In this principle, the energy that has to be delivered by the operating mechanism is limited and low energy spring operated mechanism can be used.

Figure 10 shows a generator circuit breaker with this type of interrupting chamber.

4. EVOLUTION OF TRIPPING ENERGY

Figure 11 summarizes the evolution of tripping energy for 245 kV and 420 kV, from 1974 to 2003. It shows that the operating energy has been divided by a factor of 5 to 7 during this period of nearly three decades. This illustrates the great progress that has been made in interrupting techniques for high-voltage circuit breakers during that period.

Figure 12 shows the continuous reduction of the necessary operating energy obtained through the technological progress.

5. OUTLOOK FOR THE FUTURE

Several interrupting techniques have been presented here that all aim to reduce the operating energy of high-voltage circuit breakers. To date, they have been widely applied, resulting in the lowering of drive energy as shown in figures 11 and 12.

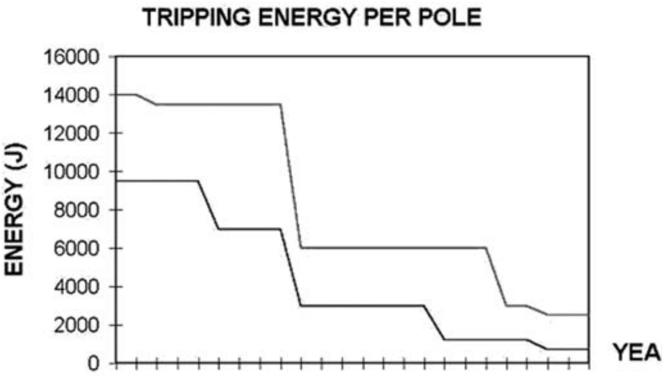


Figure 11: Evolution of tripping energy since 1974 of 245 kV and 420 kV circuit breakers

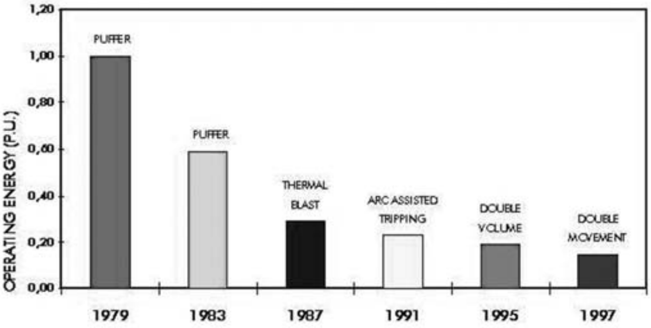


Figure 12: Operating energy as function of interrupting principle

Figure 13: GIS circuit breaker 550 kV 63 kA 50/60 Hz

The obvious question is then: what is next?

Present interrupting technologies can be applied to circuit breakers with the higher rated interrupting currents (63 kA – 80 kA) required in some networks with increasing power generation (figure 13).

Among the axis of research for future developments, investigations have been carried out on hybrid interrupting chambers where a vacuum interrupter is combined in series with a gas blast chamber. During interruption of high interrupting currents, the thermal interrupting capability is given by the vacuum interrupter and the withstand of the peak TRV is mainly provided by the gas blast interrupter.

From a technical point of view, the following considerations support the choice of hybrid interrupting chambers for applications with high breaking currents and/or low ambient temperatures:

- The short-line fault interrupting capability of gas blast interrupters is difficult to obtain at low filling pressures of SF6;
- Vacuum interrupters are known to withstand a very high rate-of-rise-of-recovery voltage (RRRV) during high short-circuit current interruption;
- The withstand of TRV peak values can be obtained with a relatively low blast pressure in the SF6 chambers, a blast pressure in any case much lower than that required for the withstand of RRRV during short-line fault interruption.

An almost obvious possibility then is to combine the high RRRV withstand capability of a vacuum interrupter and the high TRV peak withstand capability of an SF6 interrupter. In principle, the series connection of these two interrupters allows the combination of both capabilities and the ability to obtain high short-circuit interrupting capabilities with a low SF6 content.

Furthermore the authors believe that progress can still be made by further industrialization of all components and by introducing new drive technologies. Following the remarkable evolution in chamber technology, the operating mechanism represents a negligible contribution to the moving mass of circuit breakers, especially in the extra high-voltage range (≥ 420kV). Therefore the evolution of high-voltage circuit breaker technology can still be foreseen with the implementation of the same interrupting principles.

If one looks further into the future, other technological developments could lead to a reduction in the SF6 content of circuit breakers.

6. CONCLUSION

Over the last 50 years, high-voltage circuit breakers have become more reliable, more efficient, and more compact because the interrupting capability per break has been increased dramatically. These developments have not only produced major savings, they have also had a massive impact on the layout of substations with respect to space requirements.

New types of SF6 interrupting chambers, which implement innovative interrupting principles, have been developed during the last three decades, based on the objective of reducing the operating energy of the circuit breaker. This has led to reduced stress and wear of the mechanical components and consequently to an increased reliability of circuit breakers.

Service experience shows that the expectations of the designers at the beginning, with respect to reliability and day-to-day operation, have been fulfilled.

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APPLYING LOW-VOLTAGE CIRCUIT BREAKERS TO LIMIT ARC FLASH ENERGY

George Gregory, Schneider Electric/Square D Company; Kevin J. Lippert, Eaton Electrical

I. INTRODUCTION

The NFPA 70E, Standard for Electrical Safety Requirements for Employee Workplaces [1] establishes requirements associated with electrical arc flash hazards. The IEEE Guide 1584, "Guide for Performing Arc-Flash Hazard Calculations" [2], enumerates methods for numerically quantifying energy values associated with an overcurrent protective device (OCPD). Actual values from tests with circuit breakers have not been available to the P1584 committee. The authors of this paper have conducted literally hundreds of tests to determine the arc flash energy values associated with low-voltage circuit breaker performance. This paper will present the testing protocol, introduce the expectation of values from manufacturers tests and confirm that values from tests are lower than values from IEEE 1584 calculation methods.

II. TESTING PROTOCOL

A major hurdle in determining arc flash energy values associated with the performance of overcurrent protective devices has been the absence of a single industry-wide standard describing the testing protocol. While efforts are underway to establish these common requirements, several IEEE publications [3], [4], [5], [6] have established initial baseline testing parameters.

In order to simulate actual low-voltage electrical distribution equipment, all testing reported herein was performed using the "arcs in a box" setup as follows. (See Fig. 1.) Three 3/4" round CU electrodes were mounted inside an unpainted carbon steel enclosure (no cover), 1" from the back. The round electrodes were spaced 1" apart (1.75" center to center). The 1"spacing is the required phase-to-phase clearance through air for low voltage distribution equipment such as panelboards, switchboards, motor control centers and switchgear per low-voltage equipment standards.

A bare 18 AWG copper wire was used to initialize the arc at the bottom end of the round electrodes. Insulating support blocks were positioned between adjacent electrodes as needed to prevent them from bending due to forces created by the arc currents. Additionally, as needed, insulating sleeves were added over the electrodes inside the enclosure, between the bottom support block and the inside top of the enclosure, to avoid arcing between electrodes, except along the intended exposed length at the bottom, in the arc initiation area.

Calorimeters were used to obtain the actual arc energy measurements. A calorimeter is essentially a thin slice of copper held inside an insulating block. The copper's exposed side is painted black and one or more thermocouples are attached on its opposite side. The exact construction details are contained in [6]. An array of 7 Calorimeters was used, all mounted in front of the enclosure, 18" away from the centerline of the electrodes (horizontally). The 18" distance was chosen according to [5] as the "Typical working distance… sum of the distance between the worker standing in front of the equipment, and from the front of the equipment to the potential arc source inside the equipment" representative of low-voltage motor control centers and panelboards. On the array, 3 calorimeters are mounted in a horizontal row at the same height as the tip of the electrodes (vertically). A second set of three calorimeters is located in a horizontal row 6" below the elevation of the electrode tips. The middle calorimeter of each set is aligned with the center electrode (side to side). A single additional calorimeter is located 6 in above the center electrode tip.

Low-voltage circuit breakers were inserted into the test circuit electrically ahead of where the 3/4" round CU electrodes enter the enclosure (external & upstream, from the enclosure/electrodes).

The OCPD was connected from the test station to its line side using cables or bus bars sized in accordance with its continuous current rating but not more than 250 KCMIL. The load side of the OCPD was connected to the 3/4" copper electrodes using cables or bus bars with the same size restrictions as those on the line side. Each set of conductors was as short as practical and no longer than 4 feet in any case.

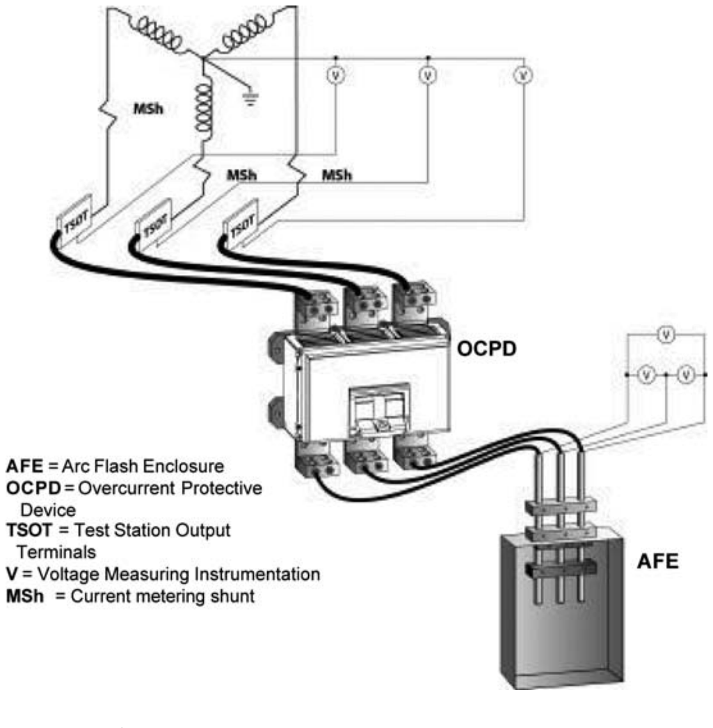

MSh
MSh
MSh
V
V
V
TSOT
TSOT
TSOT
OCPD
V
V
V
AFE
AFE = Arc Flash Enclosure
OCPD = Overcurrent Protective Device
TSOT = Test Station Output Terminals
V = Voltage Measuring Instrumentation
MSh = Current metering shunt

Fig. 1 – Sketch of Test Setup

The electrical test circuit was calibrated in accordance with UL 489, UL Standard for Safety for Molded-Case Circuit Breakers [7], Appendix C or American National Standard C37.50-1989, Low-Voltage AC Power Circuit Breakers Used in Enclosures – Test Procedures [8], Section 3.9.3 (which are considered equivalent methods for this purpose).

The data acquisition system was calibrated and capable of recording voltage, current, and calorimeter outputs as required by the tests. The temperature acquisition system had a minimum resolution of 0.1°C, a minimum accuracy of 1.5°C and acquired data for a duration long enough to capture the maximum temperature achieved. The maximum temperature rise (actual temperature – pretest reading) obtained from any calorimeter was multiplied by the constant 0.135 to obtain incident energy in calories/cm 2. Current and voltage data was acquired at a minimum rate of 10 kHz.

The circuit breaker was placed in the closed (ON) position, and the test station was then closed to energize the circuit. At least 3 tests were conducted at each circuit level in order to confirm repeatability. The highest temperature value recorded from any of these tests was used for the established value.

III. METHODS OF DETERMINING ARC FLASH VALUES

At this time, there are three basic methods of determining arc flash values for determination of flash protection boundary and for selection of personal protective equipment (PPE):

1. NFPA 70E. Table 130.7(C)(9)(a) for hazard/risk category (HRC) and Section130.3(A) for flash protection boundary. HRC is developed by assumptions of the conditions of installation. Although useful for those who have to work on a system for which little information is available, the assumptions of this approach may not match the system.

2. IEEE 1584 full calculation procedure using OCPD time-current curves. This is the most accurate method in general use. It applies detailed information to calculate values unique to the installation.

3. IEEE 1584 shortcut method for circuit breakers. This method bypasses the need for detailed information about the circuit breaker. However, it is quite conservative in that it applies the full calculation procedure to the longest duration for the circuit breaker having the longest published clearing time for the category.

Another method that this article is intended to help bring forward is application of manufacturer published values from arc flash tests performed with the OCPD directly in the circuit.

This method avoids making assumptions about performance of the OCPD and provides the most accurate information available. The earliest version of this method was employed to establish the shortcut method for fuses in IEEE 1584.

This method of testing with the OCPD in the circuit involves an enormous volume of testing, which is one reason the public has not seen published values earlier. By application of the laws of physics and information regarding the performance of the OCPD, it may be possible to model the occurrence and output the incident energy value. This kind of modeling is a topic to look to for the future.

IV. TYPICAL OUTPUT OF CALCULATED VALUES

Figure 2 illustrates typical output for 400-ampere molded-case circuit breakers (MCCBs). Results of the IEEE 1584 full calculation procedure for a standard thermal-magnetic circuit breaker and for a current limiting (CL) circuit breaker are shown.

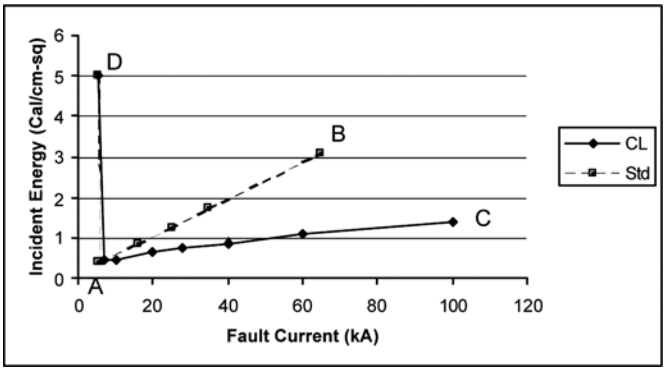


Fig. 2 – Typical calculation output for 400A standard and current-limiting MCCBS.

Curve A-B is typical of the characteristic anticipated for incident energy of a circuit breaker using time-current curves and the calculation method of IEEE 1584. That is, as the bolted fault current increases the incident energy increases.

The total electrical energy is calculated using equation 1.

(Eq. 1) E= ?v(t)*i(t) dt

Incident energy impressed on a surface a distance away from the arc can be expected to be proportional to total energy. For the standard circuit breaker, clearing time remains much the same for all current levels as the current level increases above the instantaneous trip setting.

Notice that the characteristic has a discontinuity at the point A, such that we see the incident energy rise sharply in curve A-D. The point A is where the available bolted fault current condition results in an arc current equal to the instantaneous trip point for the circuit breaker. Above this current value, the circuit breaker clears instantaneously, without any intentional delay. Below this current value, the circuit breaker clears on its long time characteristic so that the duration will increase considerably.

For the CL MCCB, we see that curve A-C is considerably lower than curve A-B. The difference is because the CL circuit breaker clears within one half cycle and current as well as time are limited as fault current increases.

V. TEST RESULTS

Figures 3 and 4 illustrate typical output from tests with the circuit breaker in the circuit.

In Fig. 3 we see 5 tests at each current level. Recall that the procedure calls for at least three tests at each current level.

The multiple tests are necessary because of the normal variation in arc current from test to test. The dispersion of incident energy values at each current level is evident from Fig. 3. The highest value is used as the published value.

Using that criterion, a value indicated by the solid curve would be published.

Fig. 4 is a similar chart for a special 800 A low-voltage power circuit breaker (LVPCB) designed to operate more rapidly than the standard power circuit breaker for the purposes of arc flash protection. Again, three or more tests are done at each current level and the published value is the highest value. The published values are represented by the solid curve on the chart.

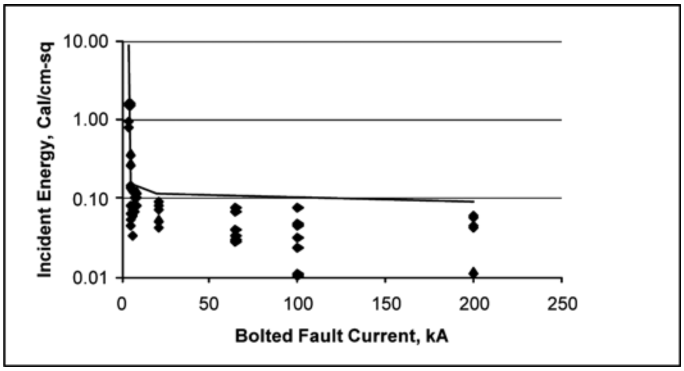


Fig. 3 – Test values using 600 A current-limiting MCCB.

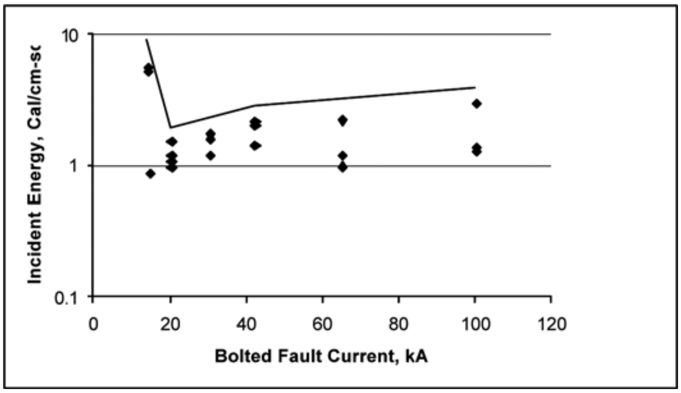


Fig. 4 – Test values using 800 A low-voltage power circuit breaker.

Figures 3 and 4 illustrate the method and the resulting information. They also illustrate the extensive amount of testing required to provide information for each rating of each circuit breaker. Therefore, the calculation methods are available for the many analyses being done while this test information is developed.

VI. COMPARISON OF RESULTS

Fig. 5 compares incident energy values for a typical 400 A MCCB using three methods of determination, IEEE 1584 full calculation method, IEEE 1584 shortcut and direct test values.

As expected, shortcut values are highest because they represent the longest duration MCCB for the industry. Values from direct tests are lowest.

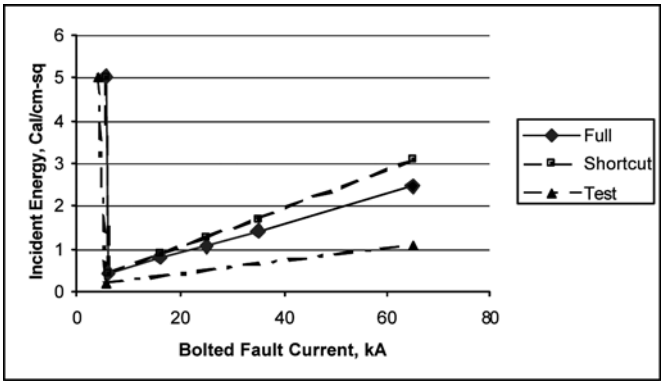


Fig. 5 – Comparison of incident energy values for three methods of determining incident energy.

Values from direct tests are lowest because they reflect the actual performance of the circuit breaker as opposed to using values from trip curves. There are two significant reasons for the difference. First, time-current curves are generally drawn to assume a conservatively long clearing of the circuit breaker. Actual values are obtained by test and then frequently rounded up to the next normal current zero for determination of the published curves. For example, if the circuit breaker clears in 11 ms during its longest operation at 600 V, the curve will be drawn to show clearing at 16.7 ms, a full cycle. The same circuit breaker at 480 V may clear within 8 ms, but the time-current curve still shows clearing in 16.7 ms. When trip curve values are used for calculations, they will be conservative in duration.

The second difference relates to current. As the circuit breaker is clearing, it develops an arc between its contacts.

The dynamic impedance of this arc will reduce the current flowing and will, in that way, reduce the incident energy. The calculation methods assume full arc current as though the arc in the circuit breaker was not present.

Using Fig. 5 and hazard categories as outlined in Table 130.7(C)(11) of NFPA 70E for a 480 V bolted fault level of 65 kA, we would find that HRC 1 PPE would be required if calculations using either the full or shortcut methods of IEEE 1584 were applied. Category 0 PPE would be required for application of direct tested values. If we were to apply Table 130.7(C)(9)(a) of NFPA 70E, HRC 2 PPE would be required for voltage testing of equipment. The most accurate method is the use of direct tested values and it is also the lowest in this case.

Table 1 shows tested values in comparison with calculated values for a number of MCCBs. By applying the lower and more accurate values, often lighter rated PPE can be applied, which reduces the heat and encumbering effect on workers, and may improve their ability to perform the work safely.

VII. APPLICATION RECOMMENDATIONS

Whenever possible, trip units should be set for instantaneous operation. Operation with no intentional delay greatly aids in reduction or arc flash energy when it can be implemented without reducing needed selective coordination.

Be aware of the fault current that would result in operation below the instantaneous range. Below that value, duration of the fault can be long and calculated incident energy can be high.

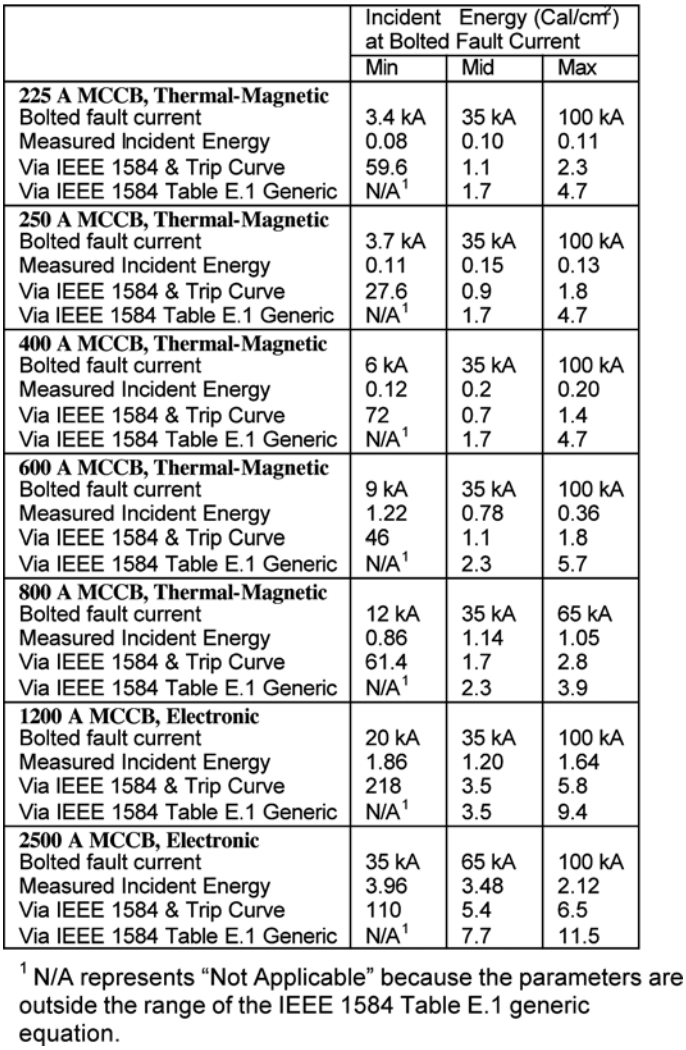
Adjust settings to the lowest level that will allow operation of the facility.

VIII. ZONE SELECTIVE INTERLOCKING

Many electronic trip units offer a communication feature known as Zone Selective Interlocking (ZSI). Two or more breakers connected in series are interconnected with a twisted pair of communication wires between their trip units.

With ZSI, upstream breakers receive a signal to delay tripping for a preset interval while the downstream circuit breaker clears the fault. However, when no signal is received from the downstream breaker, ZSI bypasses the preset short delay time and ground fault delay time (when available) on the upstream circuit breaker closest to the fault, which then trips with no intentional delay. This enables instantaneous tripping over a much wider range of fault currents while still maintaining optimal system coordination.

Table 1



	Incident Energy (Cal/cm²) at Bolted Fault Current		
	Min	Mid	Max
225 A MCCB, Thermal-Magnetic			
Bolted fault current	3.4 kA	35 kA	100 kA
Measured Incident Energy	0.08	0.10	0.11
Via IEEE 1584 & Trip Curve	59.6	1.1	2.3
Via IEEE 1584 Table E.1 Generic	N/A[1]	1.7	4.7
250 A MCCB, Thermal-Magnetic			
Bolted fault current	3.7 kA	35 kA	100 kA
Measured Incident Energy	0.11	0.15	0.13
Via IEEE 1584 & Trip Curve	27.6	0.9	1.8
Via IEEE 1584 Table E.1 Generic	N/A[1]	1.7	4.7
400 A MCCB, Thermal-Magnetic			
Bolted fault current	6 kA	35 kA	100 kA
Measured Incident Energy	0.12	0.2	0.20
Via IEEE 1584 & Trip Curve	72	0.7	1.4
Via IEEE 1584 Table E.1 Generic	N/A[1]	1.7	4.7
600 A MCCB, Thermal-Magnetic			
Bolted fault current	9 kA	35 kA	100 kA
Measured Incident Energy	1.22	0.78	0.36
Via IEEE 1584 & Trip Curve	46	1.1	1.8
Via IEEE 1584 Table E.1 Generic	N/A[1]	2.3	5.7
800 A MCCB, Thermal-Magnetic			
Bolted fault current	12 kA	35 kA	65 kA
Measured Incident Energy	0.86	1.14	1.05
Via IEEE 1584 & Trip Curve	61.4	1.7	2.8
Via IEEE 1584 Table E.1 Generic	N/A[1]	2.3	3.9
1200 A MCCB, Electronic			
Bolted fault current	20 kA	35 kA	100 kA
Measured Incident Energy	1.86	1.20	1.64
Via IEEE 1584 & Trip Curve	218	3.5	5.8
Via IEEE 1584 Table E.1 Generic	N/A[1]	3.5	9.4
2500 A MCCB, Electronic			
Bolted fault current	35 kA	65 kA	100 kA
Measured Incident Energy	3.96	3.48	2.12
Via IEEE 1584 & Trip Curve	110	5.4	6.5
Via IEEE 1584 Table E.1 Generic	N/A[1]	7.7	11.5

[1] N/A represents "Not Applicable" because the parameters are outside the range of the IEEE 1584 Table E.1 generic equation.

Tested values for MCCBS compared with calculated values

IX. SUMMARY

Direct testing with the OCPD in the circuit provides the most accurate information related to application of the device for mitigation of arc flash injury. Test information is becoming available from manufacturers. The test method is that used for development of IEEE 1584 with the OCPD in the test circuit.

Personal Protective Equipment (PPE) for arc flash protection should be utilized any time work is to be performed on or near energized equipment, or equipment that could become energized! PPE consisting of simple FR shirt and pants typically results in a minimum arc rating of 4 cal/cm2, HRC 1 and is adequate for many molded case circuit breakers, over a wide range of fault currents, when operating in the instantaneous mode.

Similarly, circuits protected by many low-voltage power circuit breakers operating in their instantaneous mode result in HRC 2 or lower. PPE consisting of conventional cotton underwear, in addition to the simple FR shirt and pants, typically results in a minimum arc rating of 8 cal/cm2, HRC 2 and is adequate for these circuits. Engineers must be aware that operation in the instantaneous mode for power circuit breakers may result in reduction of coordination.

Extensive testing confirms that low-voltage circuit breakers provide an excellent method to reduce the energy during an arc flash incident. Current-limiting circuit breakers especially reduce incident energy by reducing both duration and fault current during an event. The added protection is not shown by calculation methods, which only consider duration.

Note: All values expressed in this article unless otherwise stated assume a working distance of 18 inches and the arcing fault in a motor control center unit. The tested values are for specific circuit breakers that will not be identified other than by current rating. They are presented to indicate typical results that may be published by the manufacturers. Values in the article are not intended to be used for arc flash analysis. The authors recommend contacting the manufacturer of the specific overcurrent protective device for application information.

X. REFERENCES

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[3] Doughty, R. L., Neal, T. E., Macalady, T., Saporita, V., and Borgwald, K., "The use of low voltage current limiting fuses to reduce arc flash energy, Petroleum and Chemical Industry Conference Record, San Diego, CA, pp. 371–380, Sept., 1999

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[5] IEEE Guide 1584, "Guide for Performing Arc-Flash Hazard Calculations", September 2002

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[7] Underwriter's Laboratories, UL 489, UL Standard for Safety for Molded-Case Circuit Breakers,

[8] American National Standard, ANSI C37.50-1989, Low-Voltage AC Power Circuit Breakers Used in Enclosures–Test Procedures

XI. VITA

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CASE STUDIES ON MV SWITCHGEAR

P.K. Jain, P. Murugan, and D. Raina, Tata Power Company, Ltd.

I. INTRODUCTION

Medium-voltage (MV) switchgear is the critical component of a distribution network and its failure may have a significant impact on power supply reliability to the end consumer. Though a lot of emphasis is placed on the design and maintainance of the switchgear for achieving the highest level of reliability, the measures are not adequate to prevent failures. Failures can be attributed to both inadequate design, but are more often due to the inadequacy of maintenance practices which fail to prevent and detect mechanical and electrical problemsleading to failures.

Increasing load densities also put a lot of pressure on the existing aging MV switchgear infrastructure. Solutions have to cater to often-conflicting requirements of maintaining high reliability and availability while keeping the costs low and achieving highest levels of safety. With the space constraints in the existing receiving stations, retrofitting and refurbishment actions offer a feasible solution to enhance the life of the existing switchgear without adversely affecting supply to the connected consumers. Refurbishment actions also have weak links in terms of operational flexibility and rating, and require special attention in terms of safety aspects and integration.

This article describes a few occurrences on MV switchgear, analysis of the root causes and corrective and preventive action taken to avoid failures or mitigate the effects of failures.

II.TATA POWER'S PRACTICES FOR IMPROVING RELIABILITY OF MV SWITCHGEAR:

A. DESIGN PRACTICES

The design practice adopted by Tata Power is to achieve a techno-commercial optimal solution while fulfilling the following objectives:

- Reduce equipment failure
- Reduce the risk of operator error
- Reduce risk of injuries to O&M personnel
- Reduce maintenance effort
- Reduce size/space requirement
- Compliance to Standards

Modern day switchgear has a modular design with compartments. This enables faster isolation of a faulty compartment and also scalability by enabling flexibility of expansion of the panels. In the case of a fault, damage is limited to the faulty compartment and hence down time is greatly reduced.

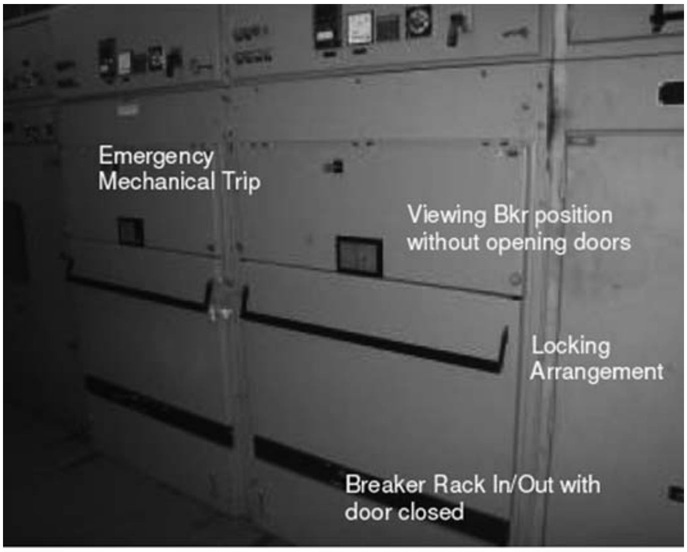
Compartment doors and barrier plates are designed to withstand pressure surges due to internal arcing. To determine the degree of protection that the switchgear provides to personnel and equipment in close proximity to the switchgear, internal arcs are initiated at specific locations inside the various switchgear compartments and the area around the switchgear is monitored.

The design incorporates a pressure relief vent to direct hot gases and molten particles away from operating personnel to protect the operator from injury and limit damage to equipment. Features like racking in/out the circuit breaker with doors closed and completely segregated low-voltage compartments provide added safety.

The equipment also incorporates on-line monitoring facilities for Load Current (Overload and Under-current limits set on SCADA System), SF6 Pressure, Trip Circuit health, spring charging etc. Breaker Monitoring Systems are connected to frequently operated breaker like controlling capacitor banks for monitoring and trending of Load Current, Timings, Coil Currents and velocity. Numerical relays provide disturbance records for fault analysis and information about trip counters and I2t that can be used as input for condition-based maintenance.

B. CONDITION MONITORING & MAINTENANCE PRACTICES

Until recently, Tata Power followed a periodic maintenance schedule for MV switchgear. The maintenance frequency was determined by the type of technology. More recently, there is a shift towards on condition based maintenance approach. The need to optimize manpower utilization and maximize equipment availability is the main driver for extending maintenance intervals for MV switchgear. This means greater reliance on condition monitoring techniques, particularly on on-line systems, to provide information on the condition of assets. Information on trip counters, I2t and breaker operation counter from numerical protection relays and the SCADA system is used for scheduling maintenance on the switchgear.


Emergency Mechanical Trip
Viewing Bkr position without opening doors
Locking Arrangement
Breaker Rack In/Out with door closed

The majority of failures on the MV switchgear has been observed on circuit breakers and hence special attention has to be given to its monitoring. A 'Breaker Monitoring System' has been developed which records and trends breaker timings, coil currents, load current, velocity, counter etc. These are being installed on critical breaker and frequently operated breakers like transformer incomers and breakers controlling capacitor banks.

Off-line condition monitoring includes periodic visual inspection for overheating, smoke marks, cracks on insulator, dust/moisture accumulation and foreign particles. The power circuit connections are tested for their tightness. Tests on circuit breaker such as contact resistance (condition of main contact); coil pick-up voltage and current measurement; close, open and trip-free time measurement; contact wipe measurement etc. are carried out. More recently, the Dynamic Contact Resistance Measurement technique has been introduced which records the signature of the contact assembly during breaker operation and gives the condition of the arcing contact. In addition to this, protection and control test, and trials are carried out. This includes relay pick-up and timing test, calibration of meters and checking of annunciations.

C. RETROFITTING AND REFURBISHMENT

The need for an upgrade of the MV switchgear was felt due to increased failure rate of the components of the switchgear, increasing fault levels, obsolescence of technology and lack of OEM support.

Considering the unavailability of space for new switchgear commissioning and also taking into account factors like minimizing shutdown time to the existing customers and quick restoration during emergencies; refurbishment and retrofitting was considered to be an optimal solution for life enhancement and upgrading of existing MV switchgear.

Though retrofitting solutions offer advantages like lower capital costs, shorter time for retrofitting, use of existing cabling and terminations etc., there are also certain disadvantages. The main one is that the type of tests conducted by manufacturers on their original switchgear are not valid for retrofitted cubicles. The suppliers of the new breaker and other equipment restrict their scope to type tests & routine tests conducted only on their equipment and not on the complete switchgear as a whole. Also, since retrofitting is done on site, special attention needs to be paid in terms of assembly, integration and alignment.

III.CASE STUDIES

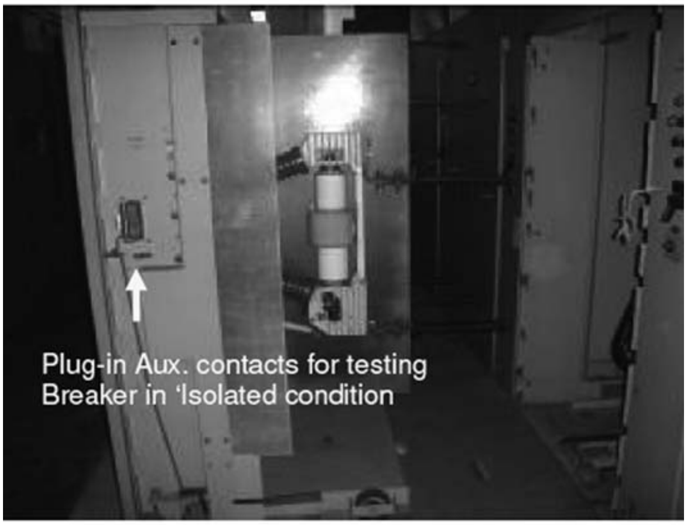
CASE STUDY – 1

Occurrence: A feeder breaker was taken out for performing condition-monitoring tests. The wires for the timing test were connected to the breaker arms and the breaker was racked in the 'test' position for performing the operations. The breaker flashed over while inserting in 'test' position.

Observations and analysis: The breaker had to be pushed into the 'test' position in order to connect the auxiliary contacts for enabling close/open operations. The breaker over-traveled due to failure of the mechanical interlock, and the metallic clamp of the test equipment connected to the breaker came into arcing distance of the live bus bar, causing the flashover.

Corrective and Preventive action taken: Plug-in connections are specified instead of sliding finger contacts for auxiliary connections. The circuit breaker is tested in 'Isolated' position.

An extension lead enables extension of the auxiliary contacts and racking in the breaker is avoided.


Plug-in Aux. contacts for testing Breaker in 'Isolated condition

CASE STUDY – 2

Occurrence: MV Breaker failed during fault clearance causing extensive damage to doors and windows of the switchgear room.

Observations and Analysis: The pressure wave caused by the arc during the breaker failure could find no way to escape, causing damage to doors and windows.

Corrective and Preventive action taken: Outlets for the pressure wave in the form of hinged louvers have been installed at various locations in the switchgear room. These louvers remain closed normally and do not allow the outside dust to enter the room. In case a pressure wave is caused due to electrical arc, the pressure is released through these louvers, thus preventing damage to the switchgear room and injury to the operating personnel present in the room.

CASE STUDY – 3

Occurrence: A flashover occurred in the breaker compartment of a feeder which was charged and was carrying no current.

Observations and Analysis: The space heater in the breaker compartment was found to be defective. The matter was referred to the OEM. After analysis, it was recommended by the OEM that to avoid condensation in the breaker compartment, the breaker should carry a minimum 30% of rated current. In the event the current was less than 30%, it was mandatory for the space heater to be in service. As the load current was zero in this case and the heater was off, there was water condensation in the compartment, which resulted in flashover.

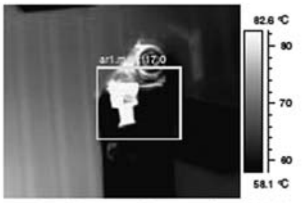
Corrective and Preventive action taken: Taking into consideration criticality of space heater health, a heater current monitoring circuit was introduced. A relay monitors the space heater current continuously and contact of the relay is connected for annunciation.

CASE STUDY – 4

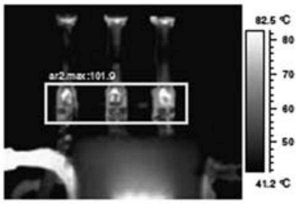
Occurrence: 22KV, 2500A Vacuum Circuit Breaker which had been retrofitted failed during service.

Observations and Analysis: It was suspected that the current carrying part of the breaker was getting overheated while carrying the nominal load current. It was decided to carry out heat run tests on a similar breaker at the manufacturer's location.

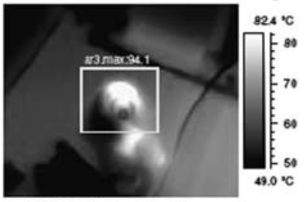
Heat run test was carried out with the breaker outside the cubicle (in open air) by passing a rated current of 2500A through the breaker. The temperature rise in the current carrying path was measured by means of thermocouples and with thermovision camera.



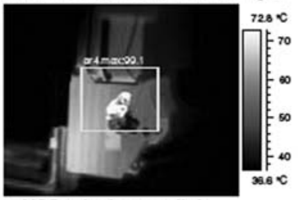
Loc. : Bolt below Vacuum Int 'A' ph
Maximum Temperature : 117.0 deg C



Loc. : Bottom connector assembly
Maximum Temperature : 101.9 deg C



Loc. : VCB tube top bolt
Maximum Temperature : 94.1 deg C



Loc. : VCB tube bottom link
Maximum Temperature : 99.1 deg C

The maximum temperature reached was 117° Celsius on the connector assembly at the bottom of the vacuum bottle. The allowable end temperature according to IEC 600694 and 62271-100 is 115°C (i.e. 75°C rise over an ambient of 40°C). The OEM informed (them) that the breaker rating was guaranteed only with the breaker in open air conditions and the rating of the breaker inside the retrofitted switchgear cubicle needed to be derated by about 20%.

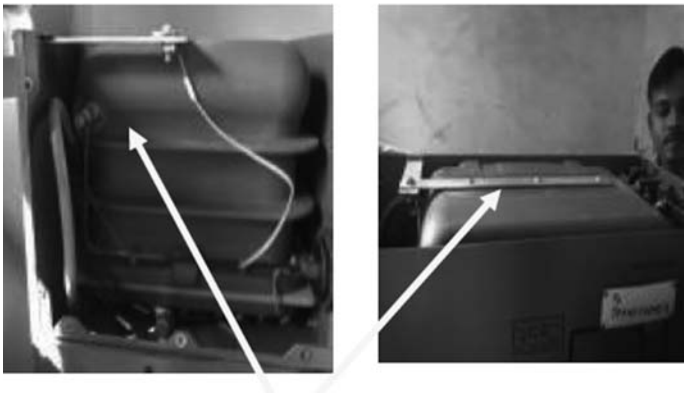
Conclusions: The breaker failure was attributed to overheating during normal load service as the temperature rise exceeded allowable limits during heat run test. To prevent overheating with the breaker inside the cubicle, a derating factor of 20% has to be applied. Thermal scanning can be an effective predictive method especially for feeders that carry more than 70-75% of the breaker/switchgear rated current.

CASE STUDY – 5

Problem: SF6 gas leakage was observed from 11kv Ring Main Units (RMUs). Five instances of SF6 gas leakage were reported in a short span of time.

Observations and Analysis: It was observed that in one RMU, there was a safety membrane failure and in 4 RMUs the leakages were from resin cast tank of the RMUs. The matter was taken up with manufacturer. The root cause identified was that the high temperature variation between the day and night temperature resulted in over-pressure and subsequent leakage.

It was suggested by the manufacturer to reduce the working pressure from 0.8bar to 0.55bar.



SF6 Leakage Points

Corrective Actions: The RMU was type tested at KEMA with lower SF6 pressure (@1.3bar abs.). The SF6 gas pressure on all RMUs of that particular make and type was reduced to 1.55bar abs. @ 20°C as suggested by the manufacturer. No leakages have been experienced since last 2-3 years.

IV. CONCLUSIONS

Much emphasis is placed on the design practices and condition monitoring practices adopted for MV switchgear, as it is a critical component in the distribution network. The challenge is to adopt new methodologies to minimize faults and mitigate the impact of failures.

Tata Power has carried out many changes in terms of installation and condition monitoring practices over the years based on their experience. Personnel safety is of paramount importance and safe testing methods like testing breakers in the ‘Isolated’ position have been adopted. Much attention has been given to the design of the switchgear room and features like hinged louvers as ‘pressurized’ rooms ensure safety and reduce the probability of faults.

Information from numerical protection relays and SCADA systems is used for data to support a condition-based maintenance approach. New monitoring systems like space heater monitoring, dynamic contact resistance measurement, and on-line breaker monitoring systems have been introduced recently and can be used as effective tools for extending maintenance cycles. Thermovision scanning has limited use in metalclad MV switchgear as the infrared rays cannot penetrate the metal sheet. But it can be effectively used during heat-run tests or when a direct line of sight to the current carrying parts is available.

Retrofitting and refurbishment of existing switchgear offers a feasible solution for enhancement of life and uprating of the switchgear. While this approach has advantages in terms of lower capital costs and completion time, care has to be taken in terms of the safety aspects with respect to the validity of the type tests after retrofitting.

BUYER'S GUIDE

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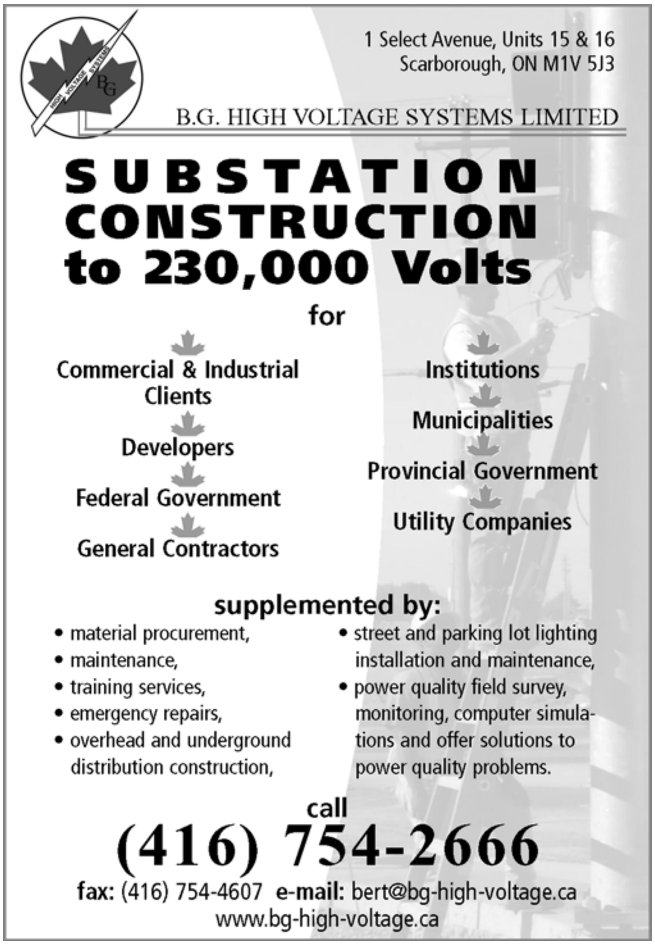
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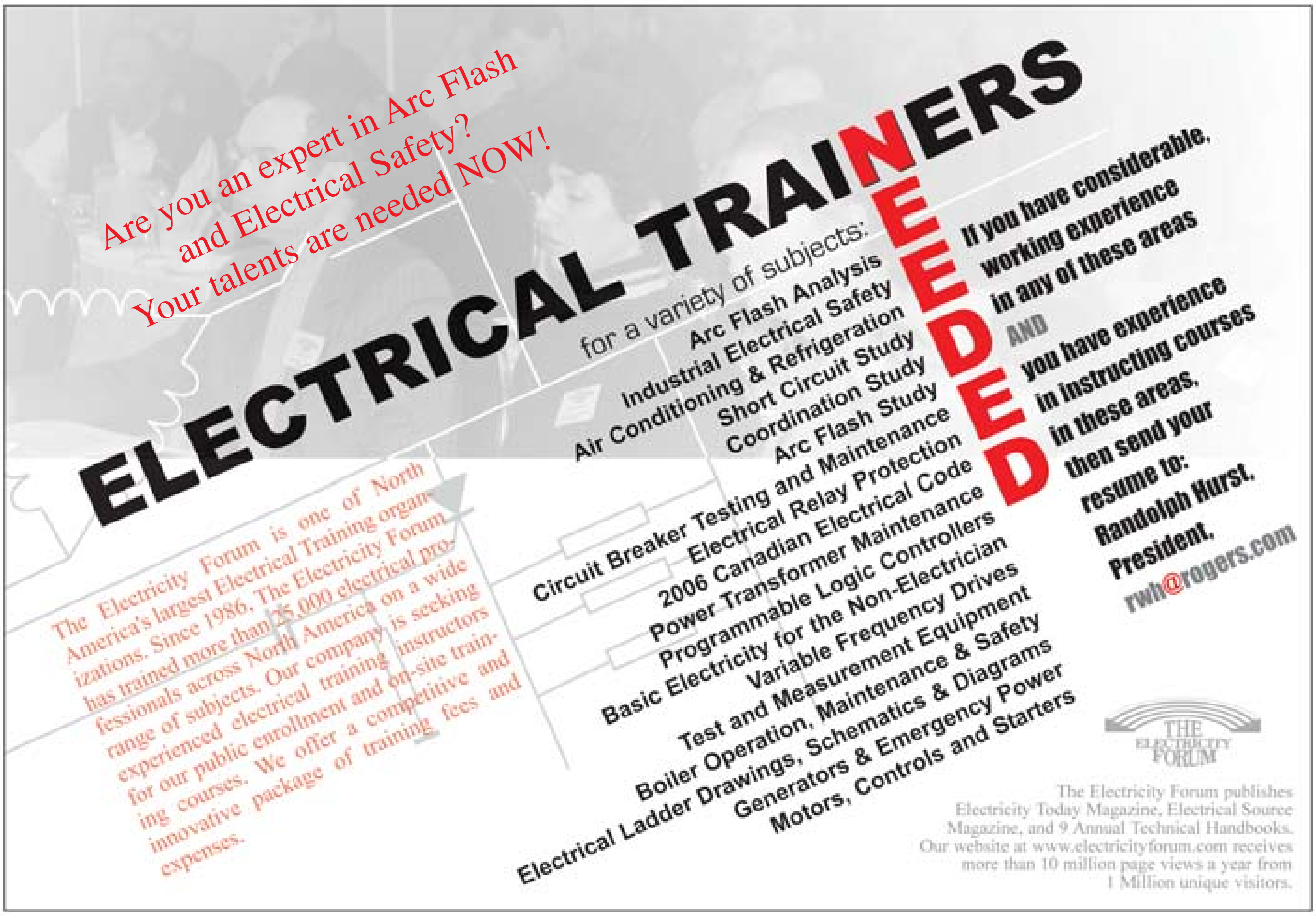

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